APPENDICES

TASK 1 - 8

APPENDICES

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Task 7 has no appendix.

TASK 1 APPENDIX

APPENDIX 1A. SIX SIGMA METHODOLOGY

A Brief Description of Six Sigma Methodologies

Much has been written of Six Sigma since Motorola pioneered it and General Electric made it popular. One of the Team members has two books on Six Sigma sitting dog-eared on his desk. The first is “Six Sigma for Everyone” by George Eckes. This is a practical and useful handbook that covers the methodologies and tools used in Six Sigma. The other is “Lean Six Sigma for Service” by Michael L. George. This contains considerably more detail and has many case studies on the use of Six Sigma to improve product quality and customer satisfaction.

Increasing customer satisfaction is the goal of Six Sigma. Thus one appropriately launches a Six Sigma effort by identifying the needs of the customer. These are expressed in broad terms, such as, “our customers need dependable and cost effective energy supplies in order to be competitive in the world market.” The product in this case is electricity and process steam, which taken together represent the energy inputs for chemical manufacturing. Those items that are “Critical to (the) Quality” of the product being purchased are known as CTQs in Six Sigma parlance. These are the factors that end users take into account when purchasing energy. If the CTQs are met, customers are happy. When customers are not happy, CTQs are used to make improvements in the way energy is purchased.

When there is no knowledge of what the CTQs are, researchers postulate a set of customer CTQs and then validate them by use of surveys or focus group meetings. (This approach was taken here and included 13 one-hour, “focus group” meetings with a variety of end users.) This results in typically five to ten CTQs. In addition, customers indicate the relative importance of each CTQ when used to evaluate the product. Thus each CTQ has a weight factor. When there are multiple responses, a simple arithmetic average is calculated.

Next customers are asked to evaluate a set of options, all of which have the potential to meet their need. With the help of the researcher, the customer evaluates each option in terms of its ability to meet each of the many CTQs. These evaluations are carried out by use of the Six Sigma Methodology.

The concepts of this method are illustrated by use of a single example. Consider the case of one end user (the purchaser, a chemical company) that plans to purchase electricity from one of two possible sources. For definiteness suppose the two sources (called options) are A, A Retail Electricity Provider and B, a Nuclear Power Plant Provider. The qualities (or characteristics) of the electricity desired by the purchaser are denoted by the CTQs (Critical to Quality). The importance of each CTQ to the purchaser is reflected by the assignment of a number (0 to 10) to the CTQ. Since some CTQs are more important to the purchaser than others, a weight W is assigned by the purchaser to each CTQ. The weights are assigned numbers of say 0 to 10.

The Six Sigma method provides a quantitative measure X of how well the important qualities of the purchaser are reflected by his (or her) choices of the CTQs and weights W. The value of this measure is found by summing the products [W] [CTQ] for each option. The measure for option A, denoted by X_A, is computed as follows for the purchase of electricity from the a Retail Electricity

Provider

$$X_A = W_{A,1}, CTQ_{A,1}, + W_{A,2} CTQ_{A,2} \quad (1)$$

where the first subscript refers to the Retail Electricity Provider and the second subscript to the number of the CTQ.

The measure for option B, denoted by X_B, for the purchase of electricity from the Nuclear Power Plant Provider is computed as follows

$$X_B = W_{B,1} CTQ_{B,1} + W_{B,2} CTQ_{B,2} \quad (2)$$

If X_B is greater than X_A, then by the Six Sigma measure, the purchasers set of preferred qualities of the product are on the whole better satisfied by Option B than Option A.

This procedure is repeated for each company (or purchaser). For each purchaser (end user) interviewed, corresponding measures X_A and X_B are obtained that quantify how well each of these options (power sources) reflect the characteristics (or qualities) of the power that are most important to the purchaser.

APPENDIX 1B. ELECTRICITY CTQS, METRICS AND EVALUATIONS

TABLE 1B-1. CTQs for Electricity Supply
Consolidated Company Profiles

CTQs	Ave	Std Dev
Low Cost	9.33	1.07
Few service interruptions	7.96	2.72
Cost stability	7.08	2.54
Less usage of natural gas	10.0	-
High Power Quality	6.20	3.03
Flexibility to meet load profile	6.08	2.42
Supplier portfolio/credit worthiness	5.92	2.77
Predictable start of supply	4.67	2.27
Air emissions	3.33	3.59

TABLE 1B-2. Metrics (Averaged over All Customers Surveyed)
Consolidated Company Profiles

Metrics	Ave	Std Dev
Low cost in cents per kWh	33.33	7.07
Tolerable service interruptions per year	5.43	14.78
Cost stability as measured by maximum length of PPA, months	6.38	8.20
Decrease use of natural gas for generating electricity as much as possible, as soon as possible	Note 1	Note 1
High Power Quality/Specs on voltage fluctuations (scale of 1 to 5)	2.58	1.08
Flexibility to meet load profile (scale of 1 to 5)	2.00	1.04
Supplier portfolio/credit worthiness (scale of 1 to 5)	3.80	1.48
Start of supply within "X" months of contract date	9.00	3.67
Air emissions	Note 2	Note 2

Note 1: It is a challenge to devise a representative metric for this CTQ. While the increase in natural gas prices is on everyone's mind, it is not necessarily an explicit consideration when making a decision to procure energy. Many chemical processes use natural gas as a feedstock or energy source (process steam from a cogen unit) for which, as the end users advise, there is no feasible substitute. Generating steam at the temperatures and pressures required, for instance, require the high temperatures that a Combustion Turbine produces. However, all perceive an indirect benefit to them of new nuclear capacity because it would begin to ease the pressure on the cost of natural gas and there is a decided sense of urgency attached to this. The most representative metric for using less natural gas is to decrease its use for generating electricity "as much as possible, as soon as possible."

Note 2: Chemical manufacturing facilities produce air emissions that are subject to regulation. In non-attainment areas such as Houston and Galveston (Dallas and San Antonio are close to be declared in non-attainment), the demands of these regulations can be acute and may restrict plans to expand production. This in turn becomes a "business climate" issue, that is, an issue of retaining and attracting chemical manufacturers. Thus several end users indicate that air offset credits are of value to them and figure prominently in their decisions to locate their facilities in Texas. These same companies expressed a good deal of interest in a nuclear power plant that could provide air offset credits either directly to end users (along with the electricity) or indirectly by contributing to the pool of offset credits.

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

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	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%

* Relative to Total Retail Electricity Provider.

Table 1B-4. Nuclear Option Redefined[1]

ELECTRICITY OPTIONS CTQs	Weight Factors	Retail Electricity Provider	Co-generation (CHP)	Nuclear PPA at prevailing market prices	Partial ownership of nuclear plant if ROIC is 15%
Low Cost	9.3	57	57	38	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	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	0.89	0.03
STANDARD DEVIATION		25%	72%	41%	223%

* Relative to Total Retail Electricity Provider

1 During the surveys end users indicated that the appeal of nuclear electricity is diminished if its cost is equal to prevailing market prices. This was not explicitly scored but we judge that the evaluation of the nuclear option in terms of the "low cost" CTQ would drop by 50%. This results in a decline in the overall evaluation of this option from 0.99 to 0.89, as this table reveals. In exactly the same way, if this option is further recast to eliminate the assumption of air emissions credits for nuclear generation, the evaluation index falls a little further to 0.84.

TASK 2 APPENDIX

APPENDIX 2A

2A. BASIC SITING TERMS

2A-1. EXCLUSION AREA

According to 10 CFR 50.34(a)(1)(ii)(D)(1), the exclusion area must be of such a size that an individual assumed to be located at any point on its boundary would not receive a radiation dose in excess of 25 rem total effective dose equivalent (TEDE) over any two-hour period following a postulated fission product release into the containment.

The actual radius to the site boundary depends upon the design, ranging from 0.25 miles for the modular gas plants to 0.50 miles for a single unit ABWR or dual unit AP1000. The value used in the PPE bounds currently available advanced plants and is given as 0.25 miles.

2A-2. LOW POPULATION ZONE

An applicant is also required by 10 CFR Part 100 to designate an area immediately beyond the exclusion area as a low population zone (LPZ). The size of the LPZ must be such that the distance to the nearest boundary of a densely populated center containing more than about 25,000 residents ("population center distance") must be at least one and one-third times the distance from the reactor to the outer boundary of the LPZ. The boundary of the population center should be determined upon consideration of population distribution, not political boundaries.

According to 10 CFR 50.34(a)(1)(ii)(D)(2), the LPZ must be of such a size that an individual located on its outer radius for the course of the postulated accident (assumed to be 30 days) would not receive a radiation dose in excess of 25 rem TEDE.

The actual radius depends upon the design of the power plant that has its own unique characteristics, such as the plot plan and source terms for determining the releases. There is no bounding value given in the PPE for the LPZ. The LPZ for the ABWR is 3 miles and is probably representative of advanced designs.

2A-3. EMERGENCY PLANNING ZONES[1]

To facilitate a preplanned strategy for protective actions during an emergency, there are two emergency planning zones (EPZs) around each nuclear power plant. The exact size and shape of each EPZ is a result of detailed planning which includes consideration of the specific conditions at each site, unique geographical features of the area, and demographic information. This preplanned strategy for an EPZ provides a substantial basis to support activity beyond the planning zone in the extremely unlikely event it would be needed.

The two EPZs are described as follows:

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[1] Source: NRC website http://www.nrc.gov/what-we-do/emerg-preparedness/protect-public/planning-zones.html .

Plume Exposure Pathway EPZ

The plume exposure pathway EPZ has a radius of about 10 miles from the reactor. Predetermined protection action plans are in place for this EPZ and are designed to avoid or reduce dose from potential ingestion of radioactive materials. These actions include sheltering, evacuation, and the use of potassium iodide where appropriate.

Ingestion Exposure Pathway EPZ

The ingestion exposure pathway EPZ has a radius of about 50 miles from the reactor. Predetermined protection action plans are in place for this EPZ and are designed to avoid or reduce dose from potential exposure of radioactive materials. These actions include a ban of contaminated food and water.

Figure 2A-1 below depicts a typical 10-mile plume exposure pathway EPZ map. The center of the map is the location of the commercial nuclear power plant reactor building. Concentric circles of 2, 5, and 10 miles have been drawn and divided into triangular sectors identified by letters from A to R. Municipalities identified to be within the 10-mile EPZ have been assigned numbers from 1 to 24. The triangular sectors provide a method of identifying the municipalities that might be affected by the radioactive plume as it travels.

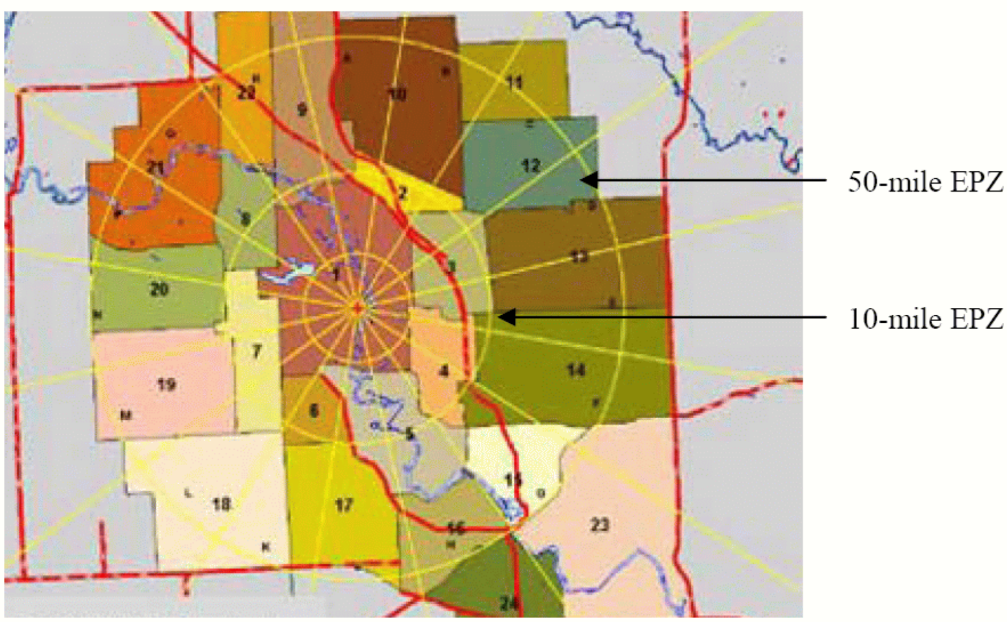


Figure 2A-1. Illustration of Emergency Planning Zone Map

APPENDIX 2B. SEISMIC EVALUATIONS

A team of experts that included members from Sandia National Lab, EnergyPath, nuclear utilities, EPRI, and others scored the site evaluation criteria suggested by the EPRI Siting Guide in terms of meeting the end-user and owner/investor CTQs. These scores are then used as weight factors. The weight factors, the metrics used to evaluate each site, and finally the evaluation itself are presented below.

Table 2B-1. Site Assessments

Evaluation Criteria	Weight Factor	Utility Functions/Metrics	Evaluation of STP	Evaluation of Comanche Peak
1. Seismic Evaluation	0.70	*The seismic characteristics of the site are such that:* Seismic modifications to the design to the design are needed - 1 Further analysis is needed to show the design meets seismic requirements - 3 Site falls within the Plant Parameter Envelope - 5	5	5
2. Permitting/Licensing Status	0.72	History of non-compliance - 1 No past Issues but a pending issue - 3 No past or present incidences of non-compliance - 5	5	5
3. Water Availability	0.35	*Assurance that a firm water supply of 35,000 acre-feet per year can be obtained:* No assurance - 1 Some assurance - 3 Reasonable assurance - 5	5	5

Evaluation Criteria	**Weight Factor**	**Utility Functions/Metrics**	**Evaluation of STP**	**Evaluation of Comanche Peak**
4. Demographic Changes	0.61	Average population density in 2050 (half of the total score) 0 persons per square mile = 5 100 persons per square mile = 4 400 persons per square mile = 1 *Distance of nearest population center exceeding 25,000 people (half of the total score)*	5	5
		The minimum requirement = 1 2x the minimum requirement = 2 3x the minimum requirement = 3 4x the minimum requirement = 4 5x the minimum requirement = 5		
5. Exclusion Area	0.65	*Expansion of the EA for purposes of hosting and constructing additional units:* Must be expanded for one unit - 1 Need not be expanded for one unit, but must be for two - 3 Need not be expanded for one or two units - 5	3	5
6. Emergency Planning	0.75	*Gaining community acceptance of the new emergency plan that will be needed if one or more units are constructed at this site will be:* Very difficult – 1 (less than green indicators/& lack of cooperation of local authorities.) Neither easy or difficult – 3 (green indicators or cooperation of authorities but not both.) No problems expected – 5 (green indicators & full cooperation of local authorities)	5	5

Evaluation Criteria	Weight Factor	Utility Functions/Metrics	Evaluation of STP	Evaluation of Comanche Peak
7. Transmission Access	0.74	5 – transmission capacity of 1500 MWs or more 4 – transmission capacity of between 1150 and 1500 MWs 3 – need capacity upgrades to the point of interconnection 2 – need capacity upgrades to the point of interconnection and to other portions of the ERCOT grid 1 – need upgrades but do not have sufficient space in existing right of ways	Not evaluated at this time	Not evaluated at this time
8. Power pricing[2]	0.93	1 – located in area with significant congestion 3 – located in area with occasional congestion 5 – located in area with no congestion	2	1
9. Plans for Existing Units[3]	0.40	1 – plans for major modifications or regulatory application 3 – plans for some modifications or regulatory applications 5 – no plans	5	5
10. Spent Fuel Storage	0.76	1 – site needs storage facility within 7 years[4] 3 – site needs storage facility in 10 years 5 – site will not need a storage facility	5	5
TOTAL SCORES			25.56	24.33

[2] after 2010.

[3] during the period of COLA review and construction.

[4] during the period of new plant construction.

APPENDIX 2B. SEISMIC EVALUATIONS

2B-1. PUBLICLY AVAILABLE INFORMATION

Extensive new information has been published subsequent to the initial assessments of the Candidate Sites A and B. These studies have used a variety of techniques to characterize the location, extent and activity of tectonic features; the location, magnitude and rates of seismic activity; and general characteristics of the areas surrounding the candidate sites. The National Earthquake Hazard Reduction Program (NEHRP) funded many of these efforts. NEHRP participating agencies includethe Federal Emergency Management Agency (FEMA) the lead agency; the National Institute of Standards and Technology (NIST); the National Science Foundation (NSF); and the United States Geological Survey (USGS). The following federal, state, national and local data sources were reviewed for this study. Specific illustrations have been captured with locations of the Candidate Sites shown accordingly.

- National Earthquake Hazards Reduction Program (NEHRP), FEMA, NIST, NSF and USGS, http//www.fema.gov/hazards/earthquakes/nehrp/

- Earthquake Hazards Program (EHP), USGS, http//earthquake.usgs.gov

    (1) Figure 2B-4: Seismicity of Texas 1990-2001

    (2) Figure 2B-13: Peak Acceleration (%g) with 10% Probability of Exceedance in 50m Years

    (3) Figure 2B-14: Peak Acceleration (%g) with 2% Probability of Exceedance in 50m Years

    (4) Figure 2B-15: 0.2 sec Spectral Acceleration (%g) with 10% Probability of Exceedance in 50m Years

    (5) Figure 2B-16: 0.2 sec Spectral Acceleration (%g) with 2% Probability of Exceedance in 50m Years

    (6) Figure 2B-17: 1.0 sec Spectral Acceleration (%g) with 10% Probability of Exceedance in 50m Years

    (7) Figure 2.5-18: 1.0 sec Spectral Acceleration (%g) with 2% Probability of Exceedance in 50m Years

- National Earthquake Hazard Mapping Project - Interpolated Probabilistic Ground Motion, USGS,http//eqint.cr.usgs.gov/eq/html/ lookup-2002-interp.html

- Quaternary Fault and Fold Database, USGS in cooperation with the Texas Bureau of Economic Geology,http//qfaults.cr.usgs.gov/

(1) Figure 2B-6: Areas of Quarternary Deformation and Faulting, Gulf of Mexico Coastal Region

(2) Figure 2B-7: Faults and Fault Areas in Texas

- National Atlas, USGS, http//www.nationalatlas.com/

  (1) Figure 2B-8: Geologic Features - Faults, Zones and Impacts (Candidate Site A)

  (2) Figure 2B-9: Geologic Features - Faults, Zones and Impacts (Candidate Site B)

- National Geophysical Data Center (NGDC), National Environmental Satellite, Data and Information Service (NESDIS), National Oceanic and Atmospheric Administration (NOAA),http//www.ngdc.noaa.gov/ngdc.html

- NOAA's National Geophysical Data Center (NGDC), Earthquake Data http//www.ngdc.noaa.gov/seg/hazard/earthqk.shtml

- CERICenter for Earthquake Research and Information http//www.ceri.memphis.edu/

- Multidisciplinary Center for Earthquake Engineering Research (MCEER) http//mceer.buffalo.edu/

- Houston Galveston Area Council (H-GAC) Hazard Mitigation Planning, http//www.h-gac.com/HGAC/Programs/Disaster+Preparedness/default.htm

- North Central Texas Council of Governments (NCTCOG) Hazard Mitigation Action Planning, http//www.hazmap.nctcog.org/

  (1) Figure 2B-5: Geology and Tectonic Features of North Texas

- Fossil Bureau of Investigation, Dallas Paleontological Society, http//www.dallaspalo.org/fbi.htm

- Texas Bureau of Economic Geology, University of Texas at Austin, http//www.beg.utexas.edu/

  (1) Figure 2B-1: Geology of Texas, 1992

  (2) Figure 2.5-2Tectonic Map of Texas, 1997

- Institute for Geophysics, University of Texas at Austin, http//www.ig.utexas.edu/

  (1) Figure 2B-3: Locations of Earthquakes and Earthquake Sequences in Texas

- Atlas of Texas Surface Waters, Texas Statewide Mapping System (TSMS), Texas

Commission on Environmental Quality (TCEQ), http//www.tceq.state.tx.us/

(1) Figure 2B-23: Brazos River Valley Basin (Western Portion, see insert)
(2) Figure 2B-24: Colorado-Lavaca Coastal, Lavaca River, and Lavaca-Guadalupe Coastal Basins

The following building codes govern industrial, commercial and residential construction in the vicinity of the Candidate Sites:

- 2003 International Building Code (IBC), http//eqhazmaps.usgs.gov/html/ ibc_maps.html

  (1) Figure 2B-21I: BC Ground Motion for the Conterminous United States - 0.2 sec period Spectral Response Acceleration (5% of Critical damping), Site Class B

  (2) Figure 2B-22I: BC Ground Motion for the Conterminous United States - 1.0 sec period Spectral Response Acceleration (5% of Critical damping), Site Class B

- US Army Corps of Engineers TI-809-04, "Seismic Design for Buildings," December 1998, http//www.hnd.usace.army.mil/techinfo/ti/809-04/ti80904.htm

  (1) TI-809-04, Appendix F Geologic Hazards Evaluations

- US Army Corps of Engineers TI-809-05, "Seismic Evaluation and Rehabilitation for Buildings," November 1999, http//www.hnd.usace.army.mil/techinfo/ti/809-05/80905page.htm

In addition to individual articles, reports, maps and regulations published by state and federal agencies, professional/academic journals were searched using the following database:

EBSCO Academic Search: This multi-disciplinary database offers full text for more than 2,050 scholarly journals, including more than 1,500 peer-reviewed titles. Covering virtually every area of academic study, Academic Search Elite offers full text information dating as far back as 1985. This database is updated on a daily basis via EBSCOhost.

GeoRef (EBSCOhost) 1785 - present. Includes information from journals, books, maps, and reports on the geology of North America since 1785 and the geology of the rest of the world since 1933. The database includes references to all publications of the U.S. Geological Survey and masters' theses and doctoral dissertations from U.S. and Canadian universities.

GEOBASE (FirstSearch) 1980 - present. Selected full text 1998 - present. Includes literature on geology, geography, and ecology.

MasterFILE Elite (EBSCOHost) 1984 - present. Selected full text 1985 - present. Provides abstracts and indexing for periodicals, covering a wide range of topics in popular magazines and scholarly journals

Ei Compendex Plus (Ovid Telnet Interface) 1980 - present. Index includes engineering and technical literature

QUAKELINE® is a bibliographic database produced by the MCEER Information Service. It covers earthquakes, earthquake engineering, natural hazard mitigation, and related topics. It includes records for various publication types, such as journal articles, conference papers, technical reports, maps, and videotapes. QUAKELINE® was launched in May 1987. The database currently provides access to about 40,000 records. The MCEER Information Service possesses all documents cited in the database.

2B-2. VIBRATORY GROUND MOTION

Both plants report very stable sites. The stable seismicity of Texas is shown in Figures 2B-3 and 2B-4. USGS Earthquake Hazards Program illustrates stability of the sites (Figures 2B-10 through 2B-18).

Using the USGS Earthquake Hazards Program, the latitude and longitude for the candidate sites were entered to determine the interpolated Probalistic ground motions at each site (Table 2B-1).

Table 2B-1. Vibratory Motion of Sites A and B

USGS EHP Interpolated Ground Motion (%g)				
	Candidate Site A (Lat: 32B .17'.52.02", or 32.29778; Lon: -97B .47' .06.15", or -97.78504)		**Candidate Site B** (Lat: 28B .47' .41.772", or 28.79494; Lon: -96B .02' .53.079", or -96.04808)	
Stem	**10% PE[b] in 50y**	**2% PE in 50y**	**10%PE in 50y**	**2%PE in 50y**
PGA[a]	1.38	3.78	1.01	3.58
0.2 sec SA[c]	3.26	8.94	2.25	7.90
1.0 sec SA	1.53	4.17	1.01	3.01
Safe Shutdown Earthquake (SSE) & Operating Basis Earthquake (OBE) Ground Motion				
	Existing Units' Criteria[d]		**New Unit Criteria**	
Site	**SSE**	**OBE**	**SSE**	**OBE**
Candidate Site A (Comanche Peak SES)	0.12 g H 0.08 g V	0.06 g H		
Candidate Site B (South Texas Project EGS)	0.10 g H[e]	0.05 g H[e]	0.10 g H[e]	0.05 g H[e]

a PGA - Peak Ground Acceleration.
b PE - Probability of Exceedance.
c SA - Spectral Acceleration.
d Minimum values in 10CFR100.
e Chapter 2.5 of references 9 & 10.

2B-3. CAPABLE TECTONIC STRUCTURES OR SOURCES

A literature search did not identify any new structures or sources (Figures 2B-2, 2B-5 through 2B-10). The thrust faults of the Ouchita Tectonic Belt (Candidate Site A) originated in the period from mid- Pennsylvanian into Permian and accompanied the uplift and destruction of the previously developed Ouachita Geosyncline. The thrust faults are buried beneath Mesozoic sediments, except in West Texas. The normal faults of the peripheral graben system, collectively termed the "older" faults of the region, are related to adjustments to conditions set up in the wake of the thrust faulting of the Ouachita orogeny.

The Candidate Site B is positioned in a belt of mostly seward-facing normal faults bordering on the Gulf of Mexico (Figure 2B-9). The gulf-margin normal faults are gravity related, and assigned as Class B structures because of their low seismicity and because they may be decoupled from underlying crust, making it unclear if they can generate significant seismic ruptures that would cause damaging ground motion (Figure 2B-6, Gulf-Margin normal Faults, No. 924).

Table 2B-2. Capable Tectonic Structures or Sources Near Site

Site	Existing Units' Criteria within 200 miles[a]	New Unit Review within 200 miles
Candidate Site A (Comanche Peak SES)	Central Texas, North of the Llano Uplift Ouachita Folded Belt Southern Oklahoma Uplifts Gulf Coast Plain Balcones fault-zone (7 mi.) Luling-Mexica-Talco fault-zone (7 mi.)	No new structures or sources identified.
Candidate Site B (South Texas Project EGS)	Ouachita Tectonic Belt (Thrust-fault); peripheral graben system at the inner or northern and northwestern periphery of the Texas Gulf Plain (Normal-fault); and Texas Gulf Plain ("growth-"faults).	No new structures or sources identified.

a Chapter 2.5 of references 9 & 10.

2B-4. SURFACE FAULTING AND DEFORMATION

No new surface faulting or deformation identified in the literature search (Figure 2B-5 through2B -10).

Table 2B-3. Surface Faulting Near Site

Site	Existing Units' Criteria Five Mile Range[a]	New Unit Criteria
Candidate Site A (Comanche Peak SES)	No evidence of Faulting	No new faulting or deformation identified.
Candidate Site B (South Texas Project EGS)	No evidence of Faulting	No new faulting or deformation identified.

a Chapter 2.5 of references 9 & 10.

2B-5. GEOLOGIC HAZARDS

USGS EHP does not identify any new geologic hazards near either site (Figures 2B-6 through 2B-10).

Table 2B-4. Geologic Hazards Near Site

Site	Existing Units' Analysis[a]	New Unit Analysis
Candidate Site A (Comanche Peak SES)	No evidence indicating actual or potential uplift or subsidence, cavernous or karst terrain, tectonic warping or deformational zones. Zones of alteration, weathering, structural weakness, unrelieved residual stresses or geologically hazardous materials are not in evidence.	No new geologic hazards identified.
Candidate Site B (South Texas Project EGS)		No new geologic hazards identified.

a Chapter 2.5 of references 9 & 10.

2B-6. SOIL STABILITY

Both plants report their sites have been very stable, since commercial operation. The literature search confirms the stability (Figures 2B-11 and 2B-12). At Candidate Site "A", there has been some minor settlement experienced on warehouse foundations in reclaimed areas (landfilled) outside the powerblock. The new unit siting will remain clear of reclaimed areas. No silting or underwater slides reported for either cooling water reservoirs.

Table 2B-5. Soil Condition (Primary/Secondary)

Site	Existing Analysis[a]	New Analysis
Candidate Site A (Comanche Peak SES)	Rock	Rock
Candidate Site B (South Texas Project EGS)	Deep Soil, no SSE liquefaction	Deep Soil, no SSE liquefaction

a Chapter 2.5 of references 9 & 10

2B-6. REFERENCES

1. EPRI, "Siting GuideSite Selection and Evaluation Criteria for an Early Site Permit Application," Technical Report 1006878, March 2002.
2. 10CFR Part 52, "Early Site Permits; Standard Design Certifications; and Combined Licenses for Nuclear Power Plants," 2004.
3. 10CFR Part 50, Appendix S, "Earthquake Engineering Criteria for Nuclear Power Plants," 2004.
4. 10CFR Part 100.23, "Geologic and Seismic Siting Criteria," 2004.
5. 10CFR Part 100, Appendix A, "Geologic and Seismic Siting Criteria for Nuclear Power Plants," 2004
6. USNRC, "Identification and Characterization of Seismic Sources and Determinations of Safe Shutdown Earthquake Ground Motion," Regulatory Guide 1.165, March 1997.
7. USNRC, "General Site Suitability Criteria for Nuclear Power Stations," Regulatory Guide 4.7, Revision 2, April 1998.
8. USNRC, "Standard Review Plans for Environmental Reviews for Nuclear Power Plants," NUREG-1555, October 1999." Geology," Section 2.6.
9. TXU, Comanche Peak Electric Station (CPSES), "Final Safety Analysis Report (FSAR)," September 2004.
10. HL&P, South Texas Project Electric Generating Station (STPEGS), "Updated Final Safety Analysis Report (UFSAR)," Revision 11.

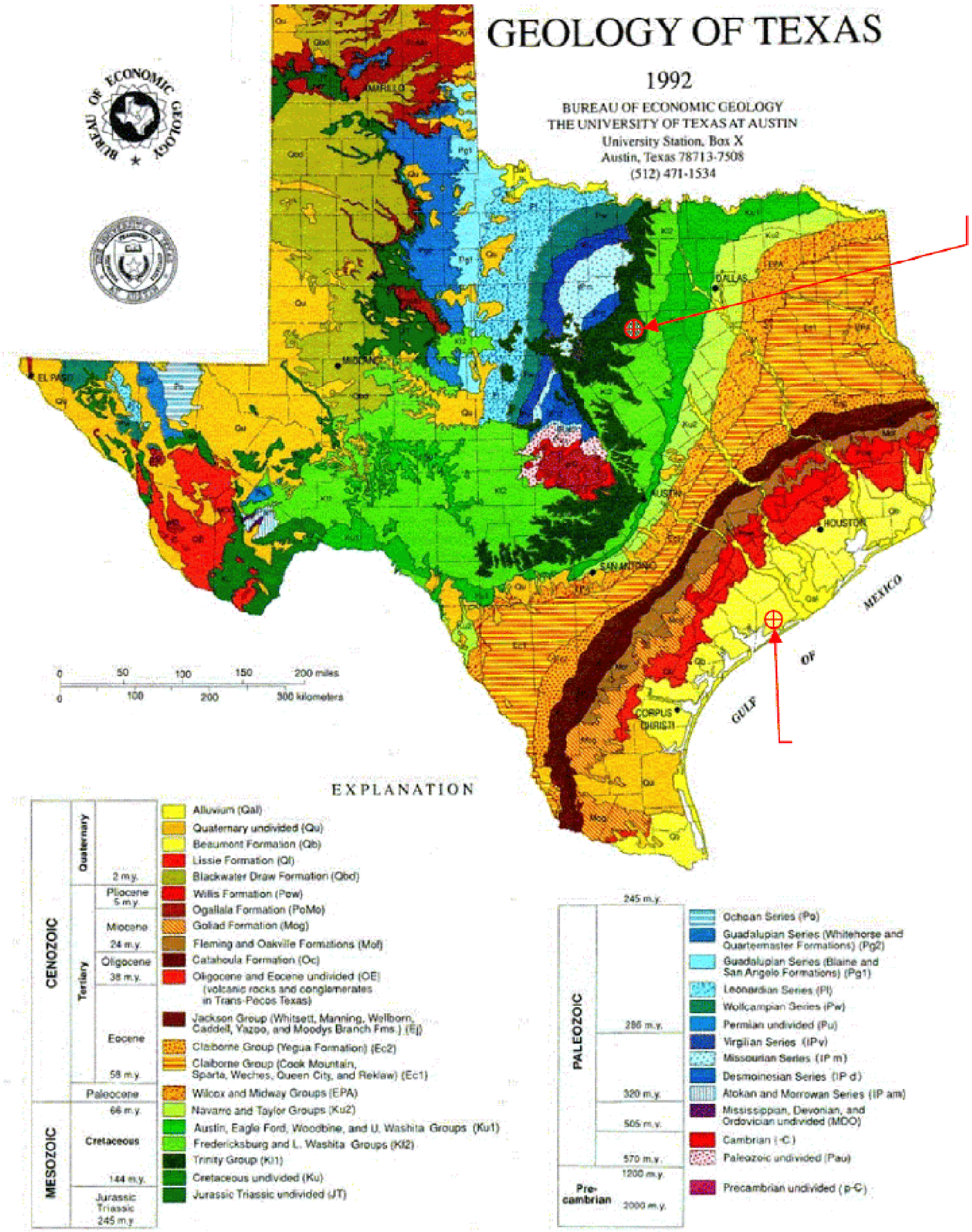


Figure 2B-1. Geology of Texas *(Source: Bureau of Economic Geology, University of Texas at Austin http://www.lib.utexas.edu/geo/texas92a.jpg)*

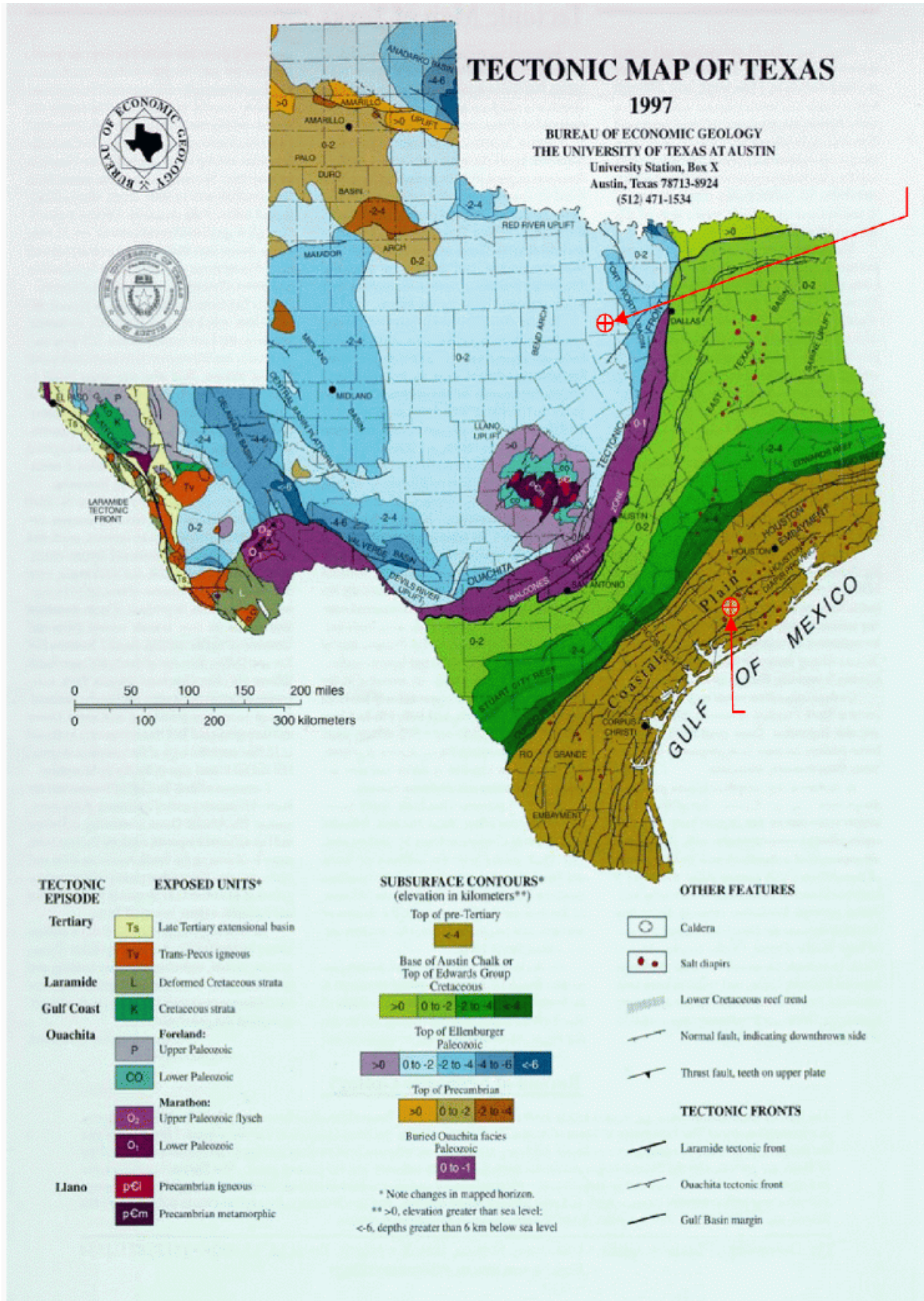


Figure 2B-2. Tectonic Map of Texas *(Source: Bureau of Economic Geology, University of Texas at Austin http://www.lib.utexas.edu/geo/tectonic2.jpg)*

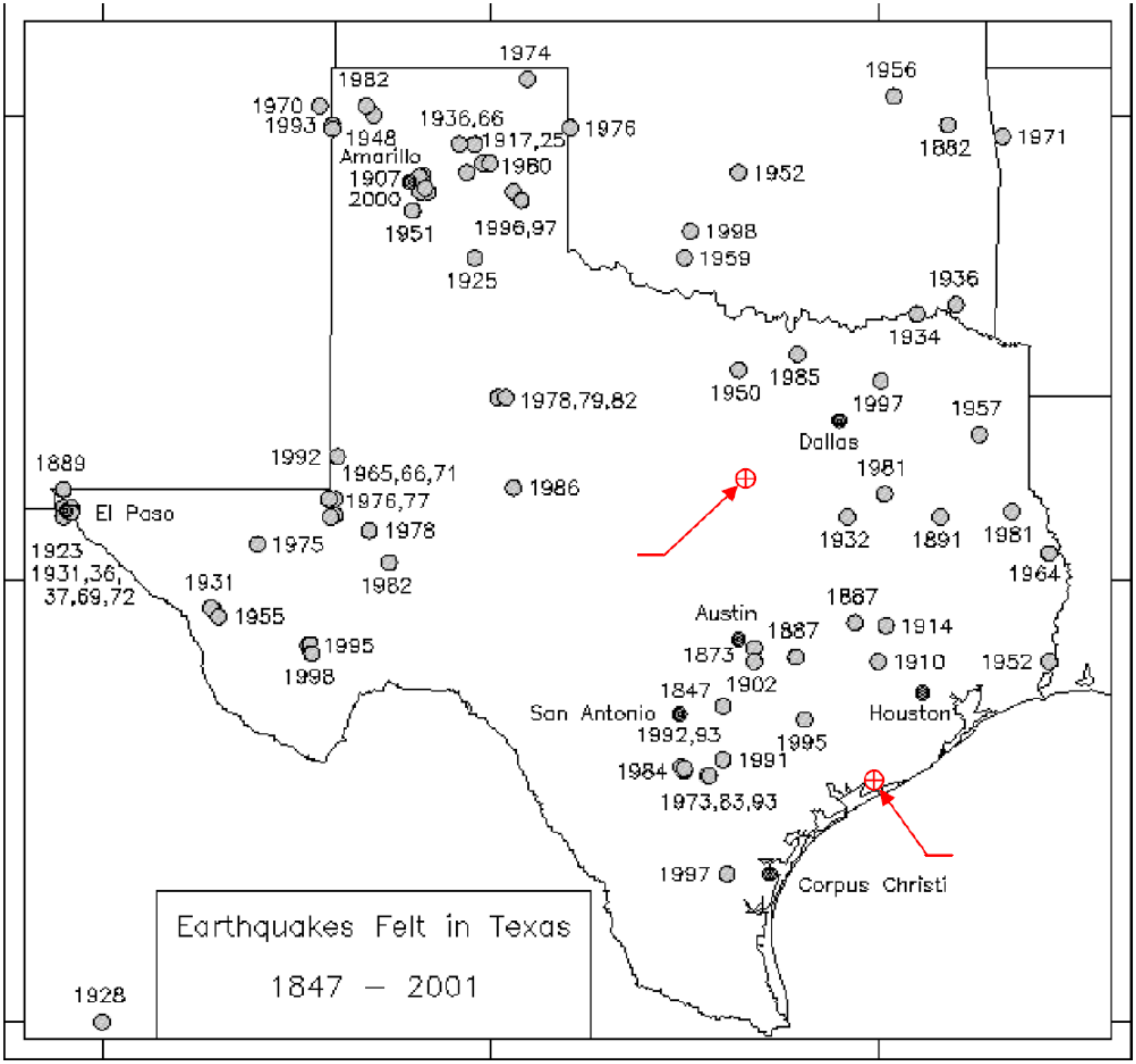


Figure 2B-3. Locations of Earthquakes and Earthquake Sequences of Texas
(Source: University of Texas - Institute for Geophysics
http://www.ig.utexas.edu/research/projects/eq/compendium/fig12_big.htm)

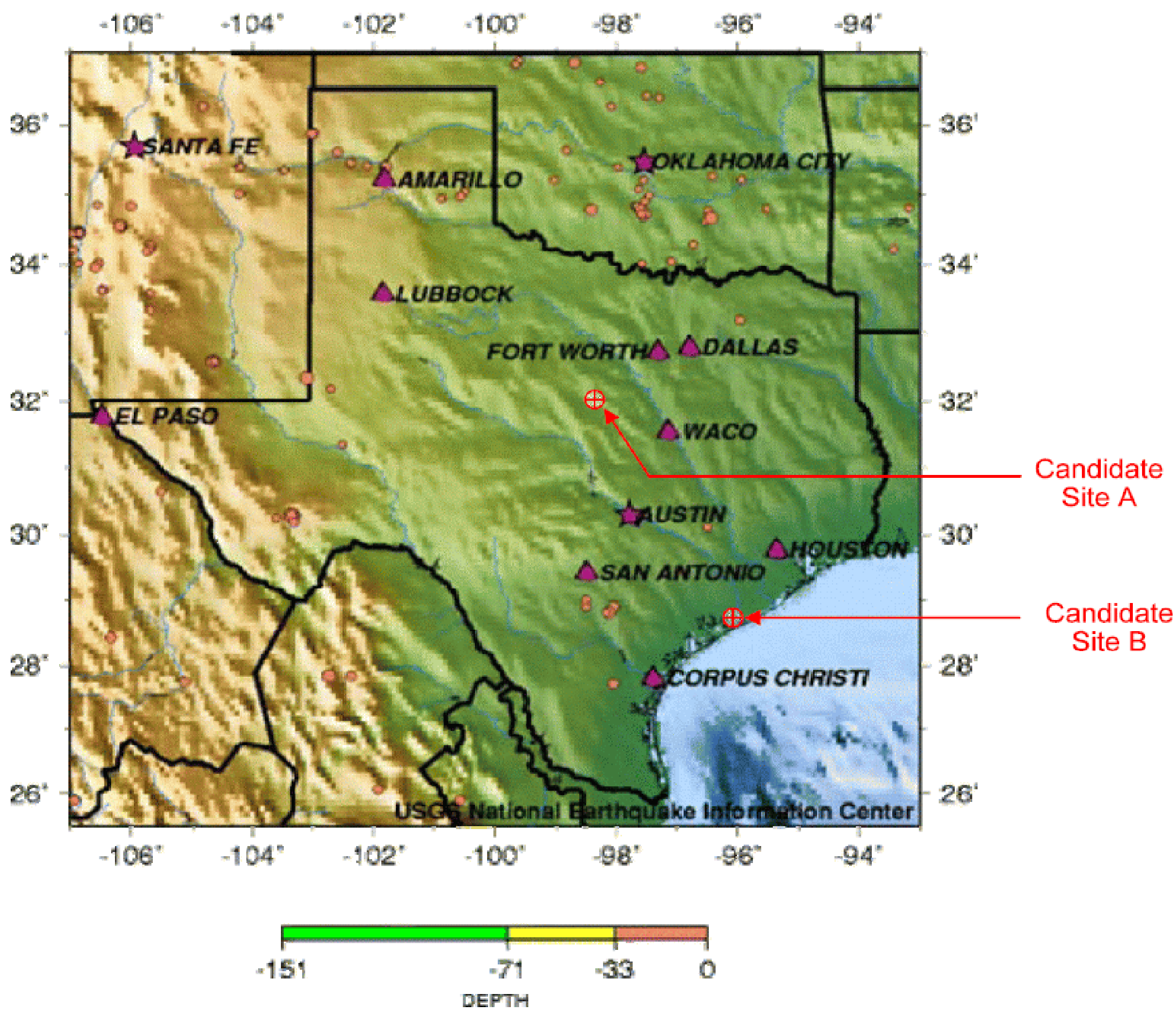


Figure 2B-4. Seismicity of Texas 1990-2001 *(Source USFS Earthquake Hazards Program http://neic.usgs.gov/neis/states/texas/texas_seismicity.html)*

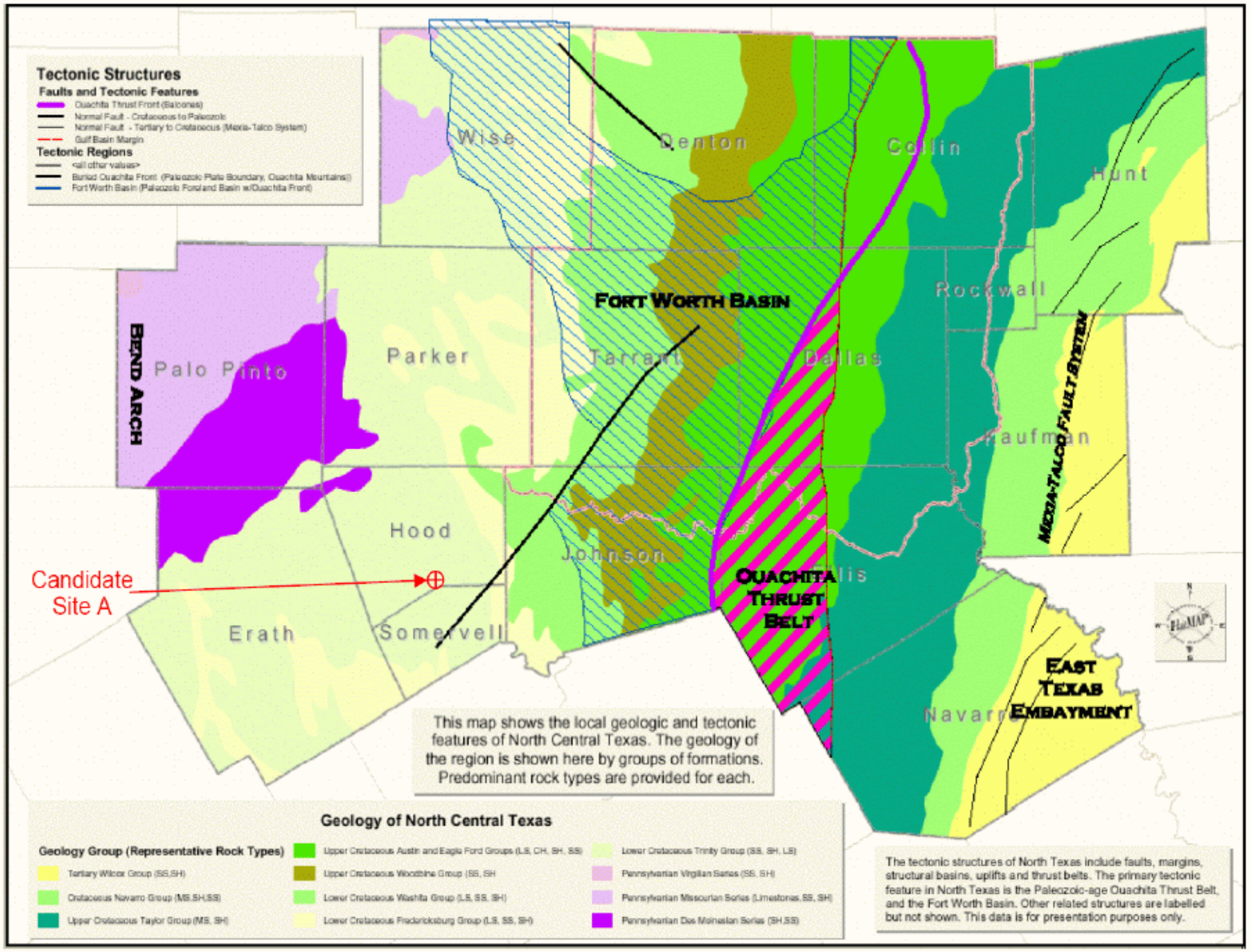
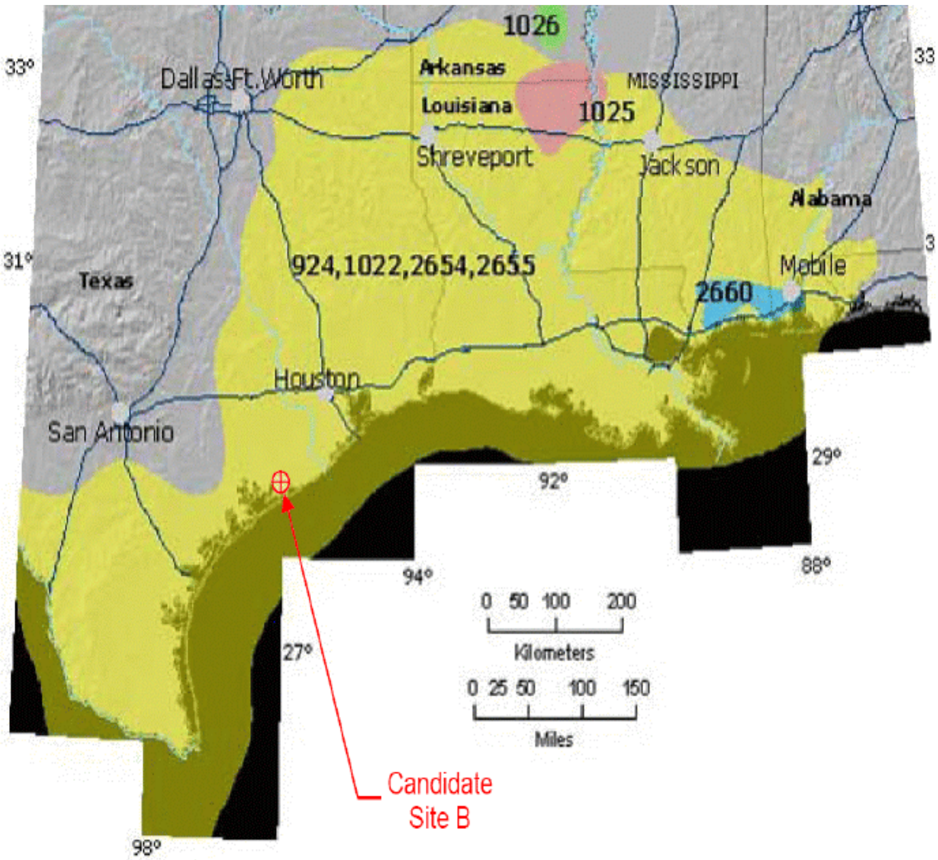


Figure 2B5. Geology and Tectonic Features of North Central Texas *(Source: North Central Texas Council of Governments - Department of Environmental Resources HAZMAP Map 1-4 http://www.hazmap.nctcog.org/risk_assessment/general/map_1_4.pdf)*



Number	Name
924	Gulf-margin normal faults, Texas
1022	Gulf-margin normal faults, Louisiana and Arkansas
1025	Monroe uplift
1026	Saline River fault zone
2654	Gulf-margin normal faults, Alabama and Florida
2655	Gulf-margin normal faults, Mississippi
2660	Wiggins uplift

Figure 2B-6. Areas of Quaternary Deformation and Faulting, Gulf of Mexico Coastal Region *(Source: USGS Quaternary Fault and Fold Database of the United States, September 18, 2003 http://earthquake.usgs.gov/qfaults/eusa/gulf.html)*

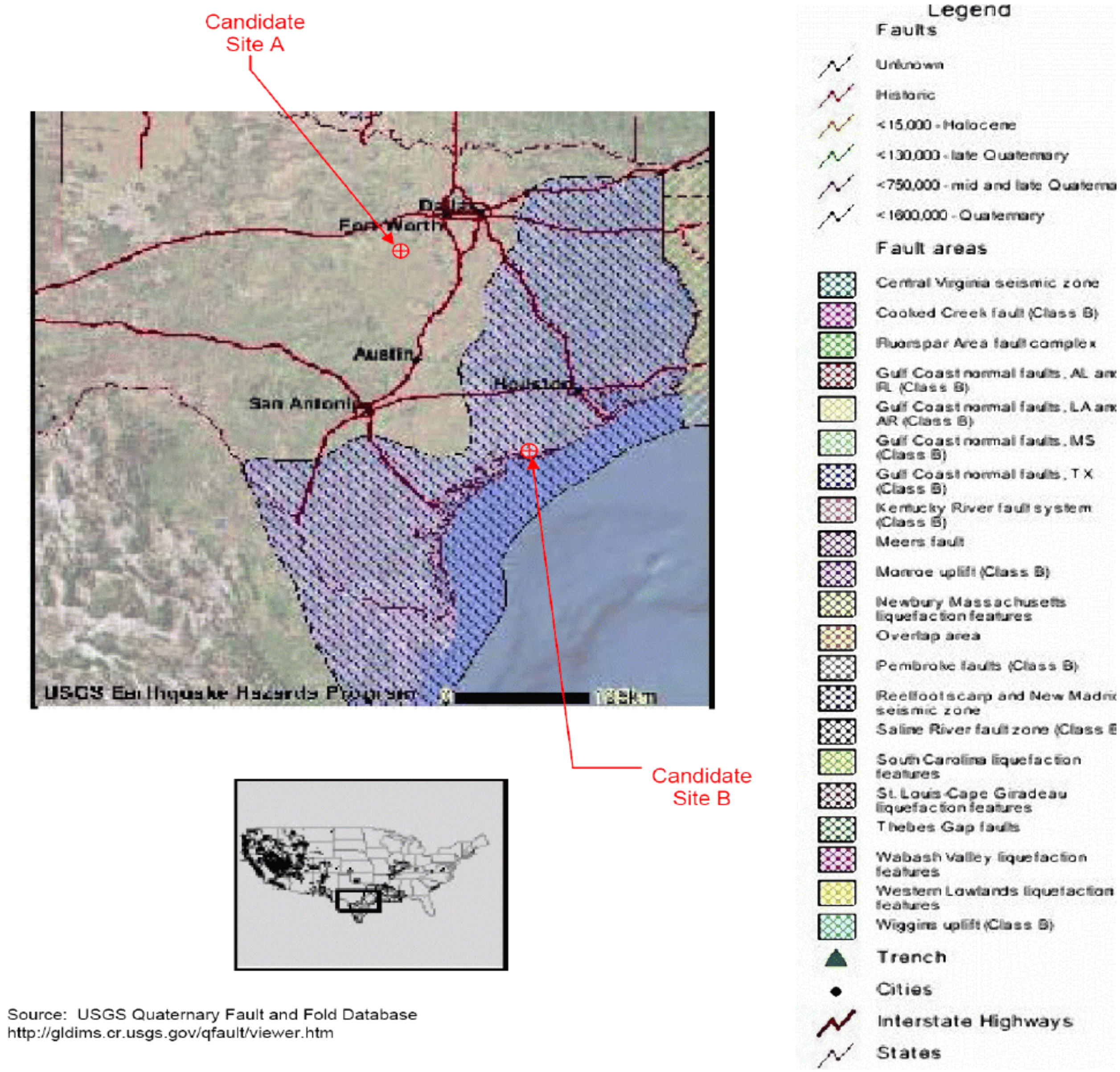
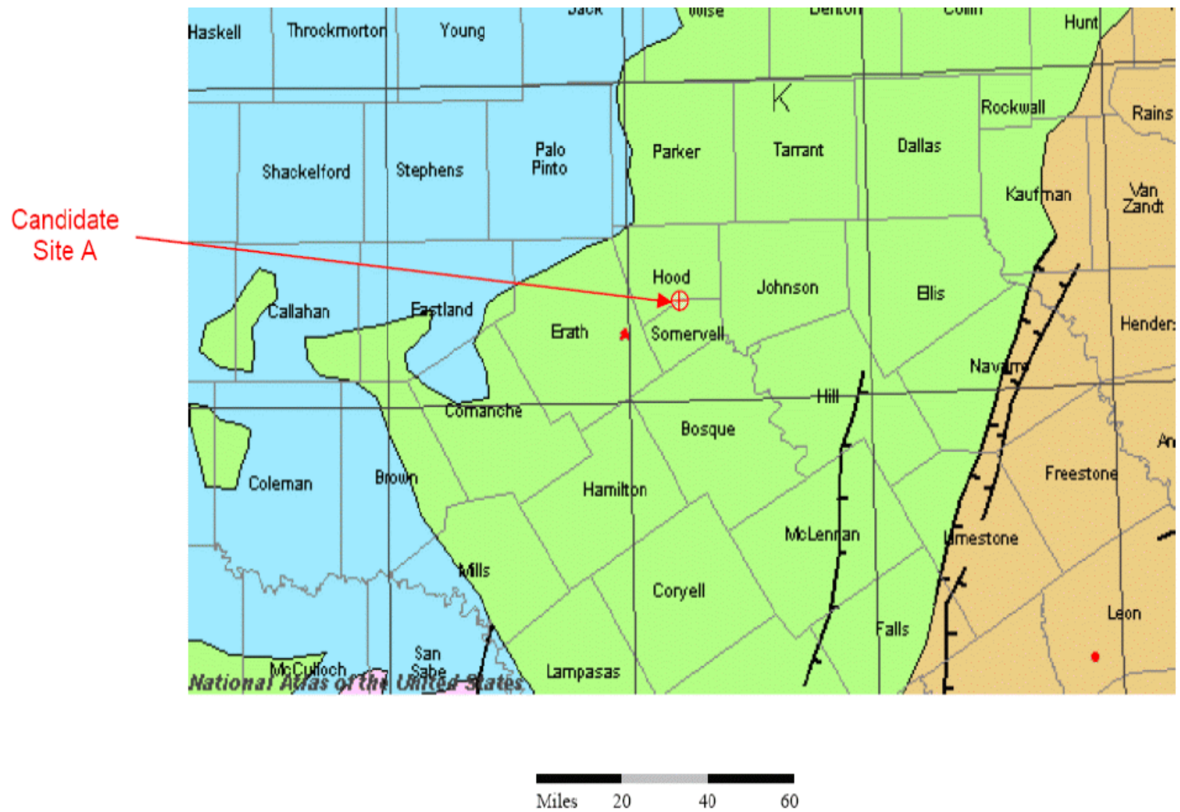


Figure 2B-7. Faults and Fault Areas in Texas *(Source: USGS Quaternary Fault and Fold Database http://gldims.cr.usgs.gov/qfault/viewer.htm)*



(See Figure 2.5-10 for Legend)

Figure 2B-8. Geologic Features - Faults, Zones, and Impacts
(Source: http://www.nationalatlas.gov (USGS, Texas Geography Network)

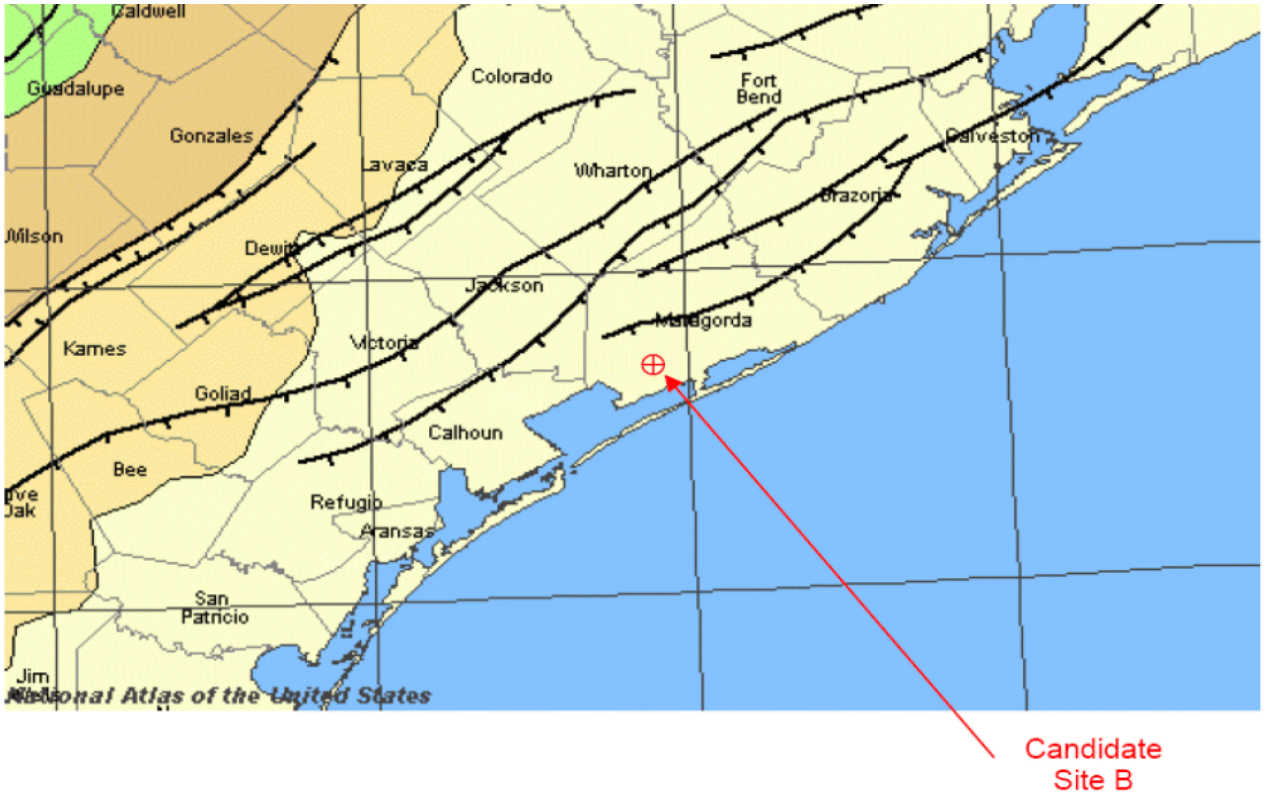
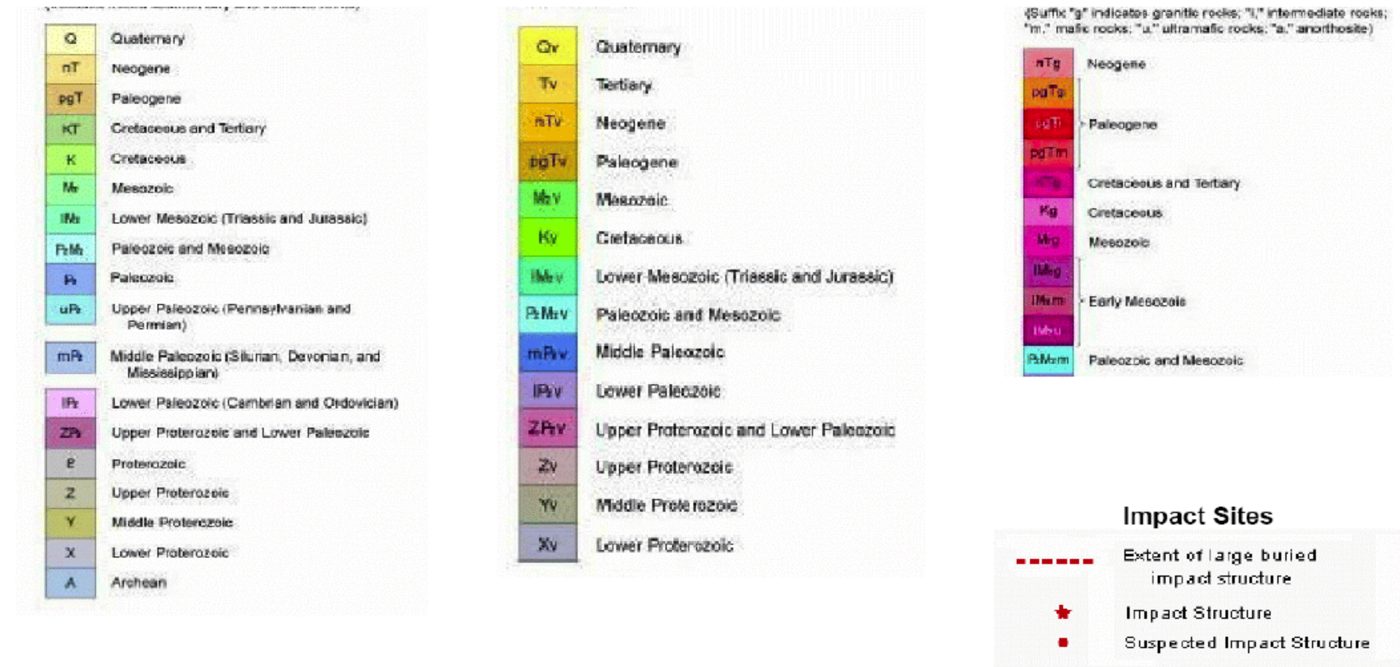


Figure 2B-9. Geologic Features - Faults, Zones, and Impacts
(Source: http://www.nationalatlas.gov (USGS, Texas Geography Network)



Source: http://nationalatlas.gov (USGS, Texas Geography Network)

Figure 2B-10. Geologic Features - Faults, Zones, and Impacts - Legend
(Source: http://nationalatlas.gov (USGS, Texas Geography Network)

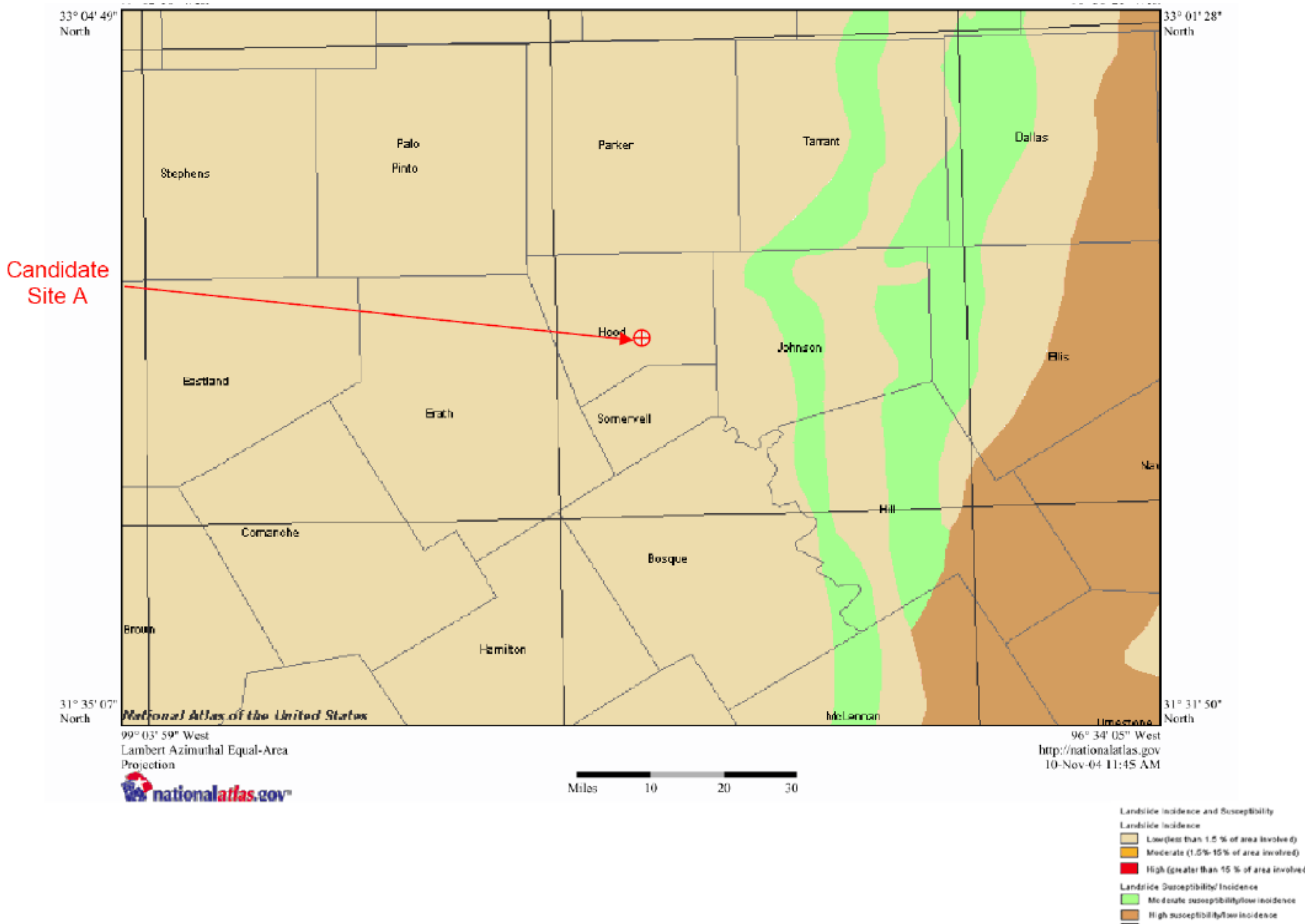
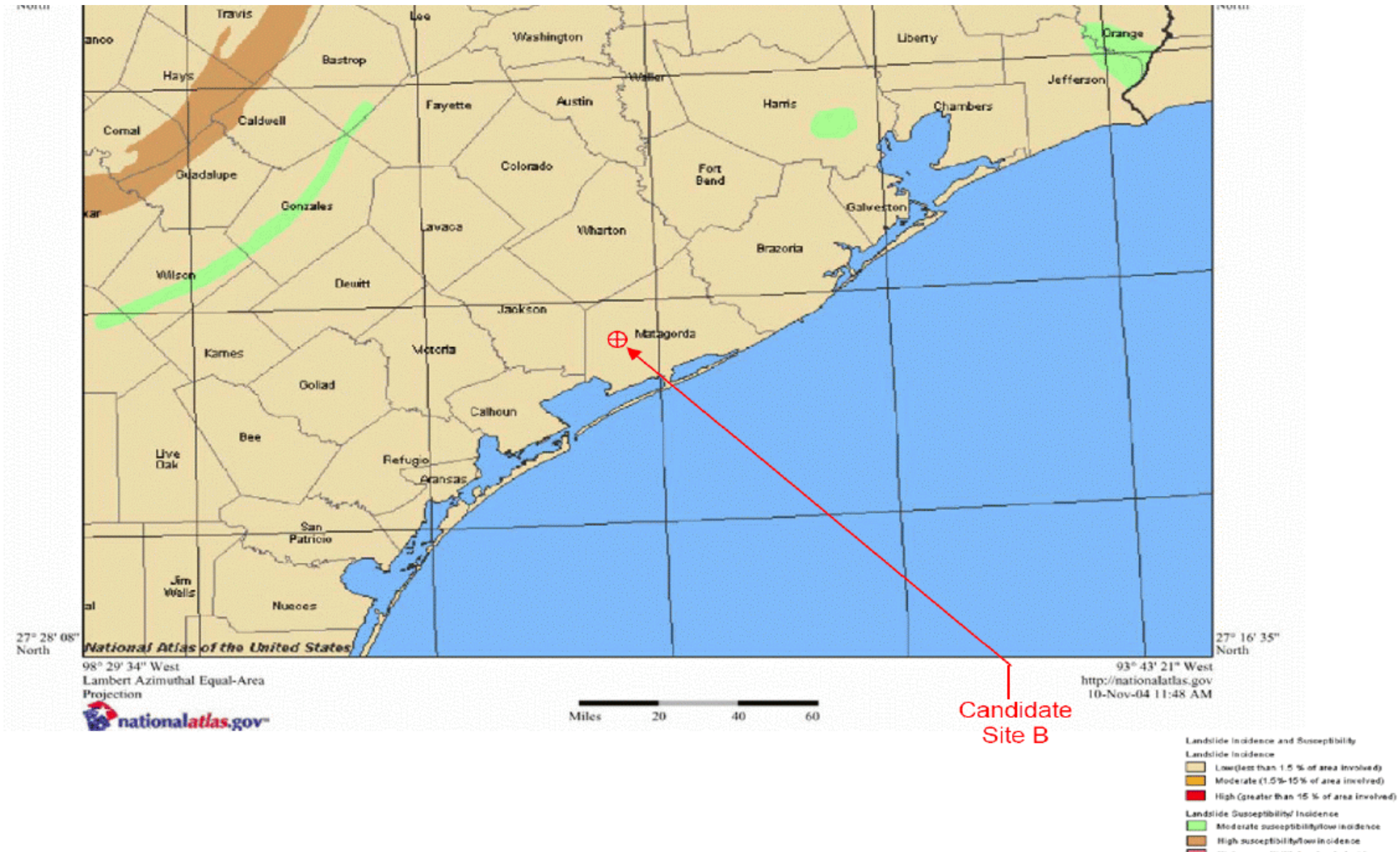


Figure 2B-11. Landslide Incidence and Susceptibility



www.nationalatlas.gov (USGS, Texas Geography Network)

Figure 2B-12. Landslide Incidence and Susceptibility

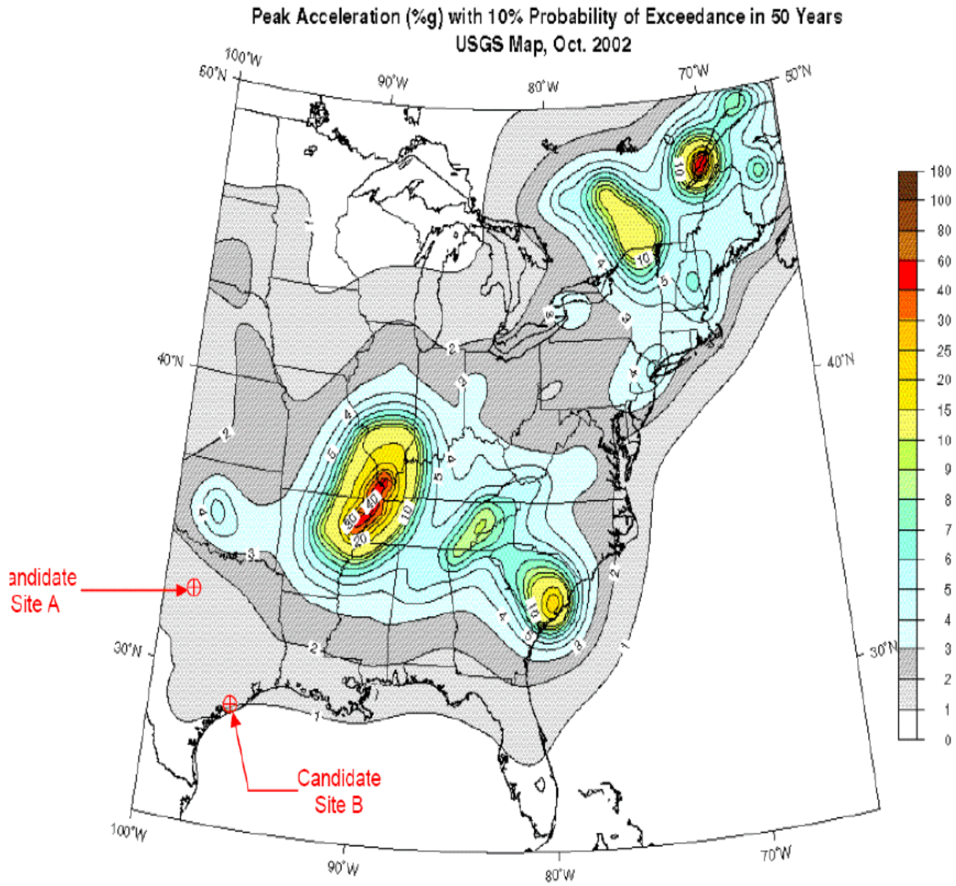


Figure 2B-13. Peak Acceleration (%g) with 10% Probability of Exceedance in 50 Years
(Source: USGS Seismic Hazard Mapping Project 2002 http://eqhazmaps.usgs.gov/html/ceus2002.html)

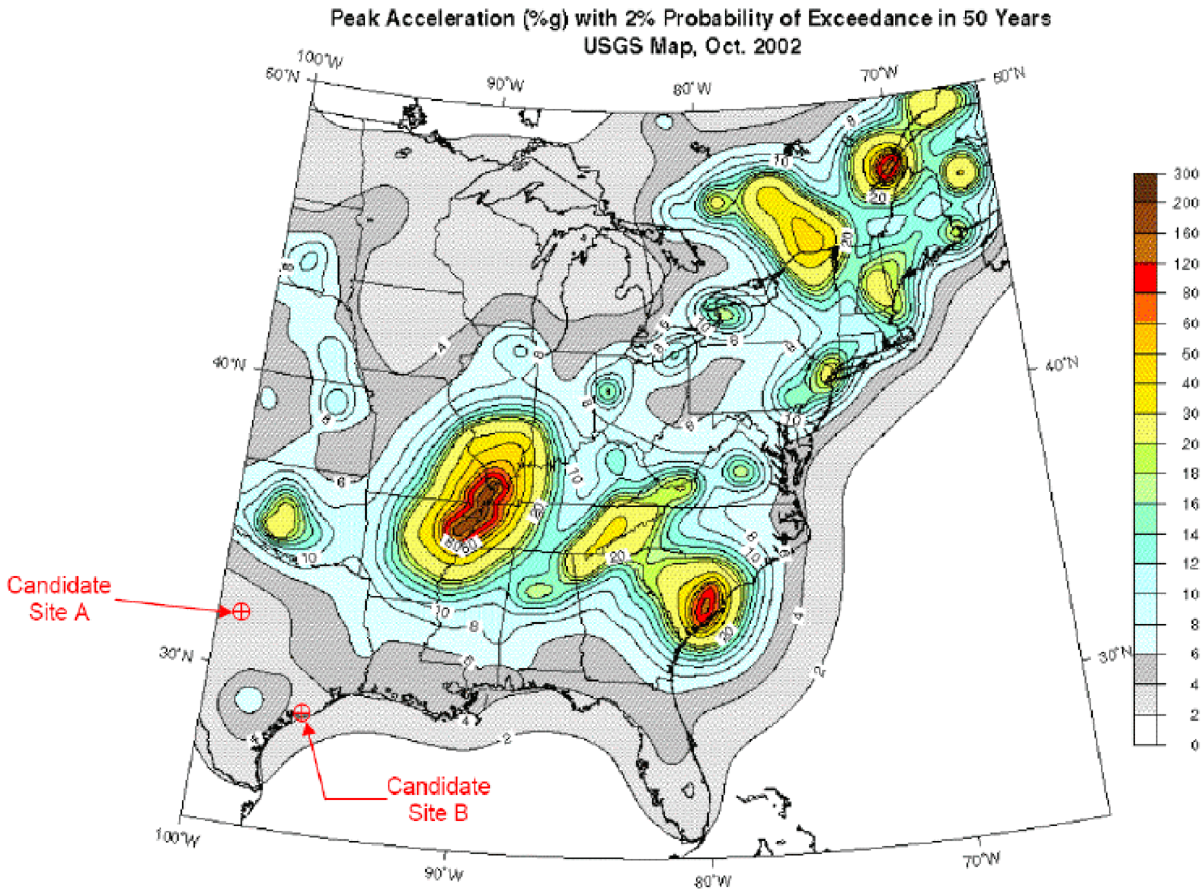


Figure 2B-14. Peak Acceleration (%g) with 2% Probability of Exceedance in 50 Years
(Source: USGS National Seismic Hazard Mapping Project 2002 http://eqhazmaps.usgs.gov/html/ceus2002.html)

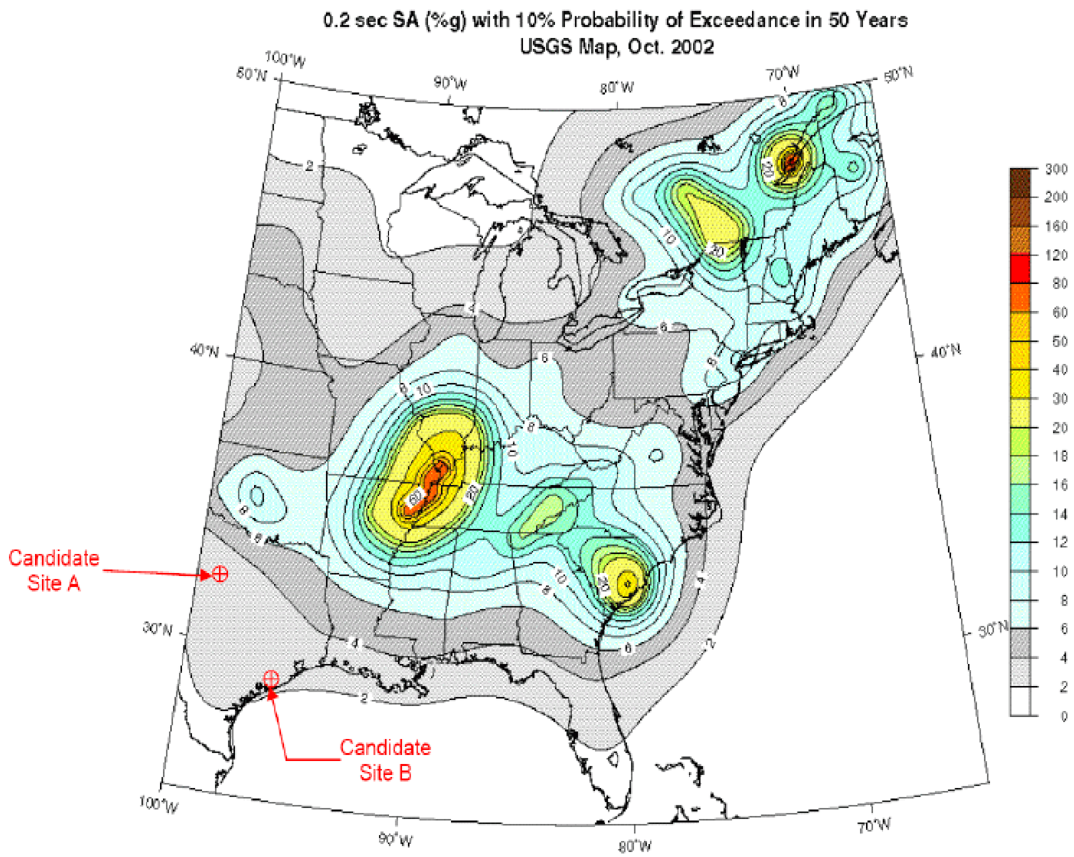


Figure 2B-15. 0.2 sec Spectral Acceleration (%g) with 10% Probability of Exceedance in 50 year
(Source: USGS National Seismic Hazard Mapping Project 2002 http://eqhazmaps.usgs.gov/html/ceus2002.html)

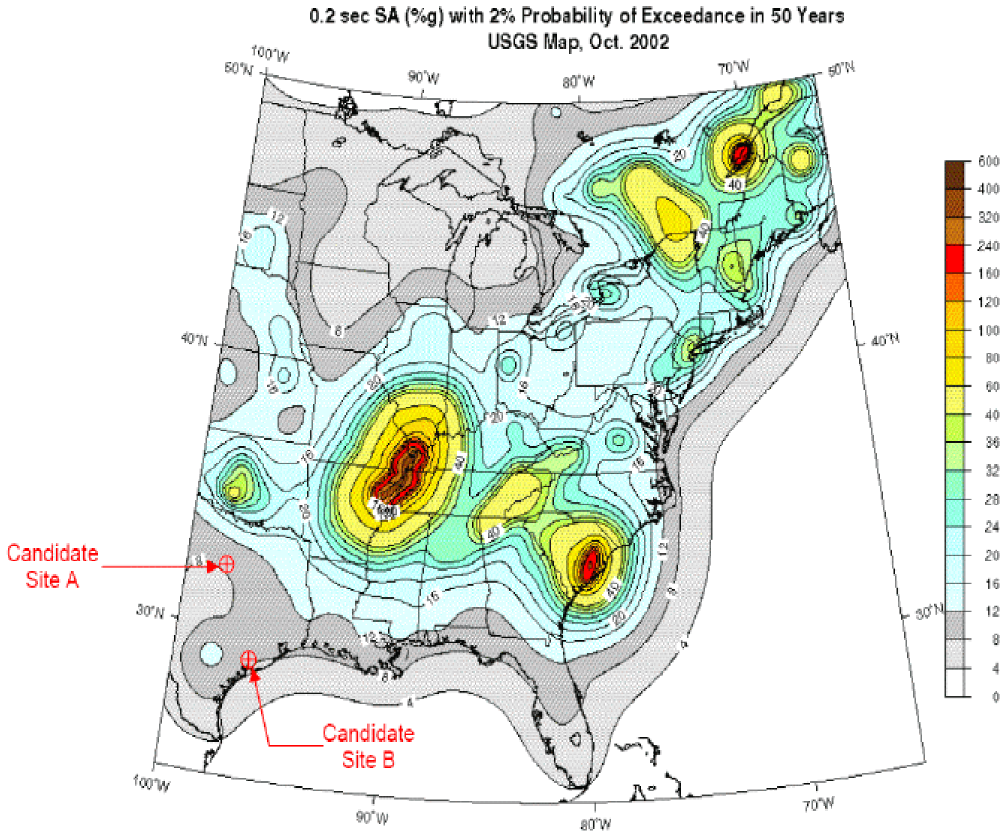


Figure 2B-16. 0.2 sec Spectral Acceleration (%g) Probability of Exceedance in 50 Years
(Source: USGS National Seismic Hazard Mapping Project 2002 http://eqhazmaps.usgs.gov/html/ceus2002.html)

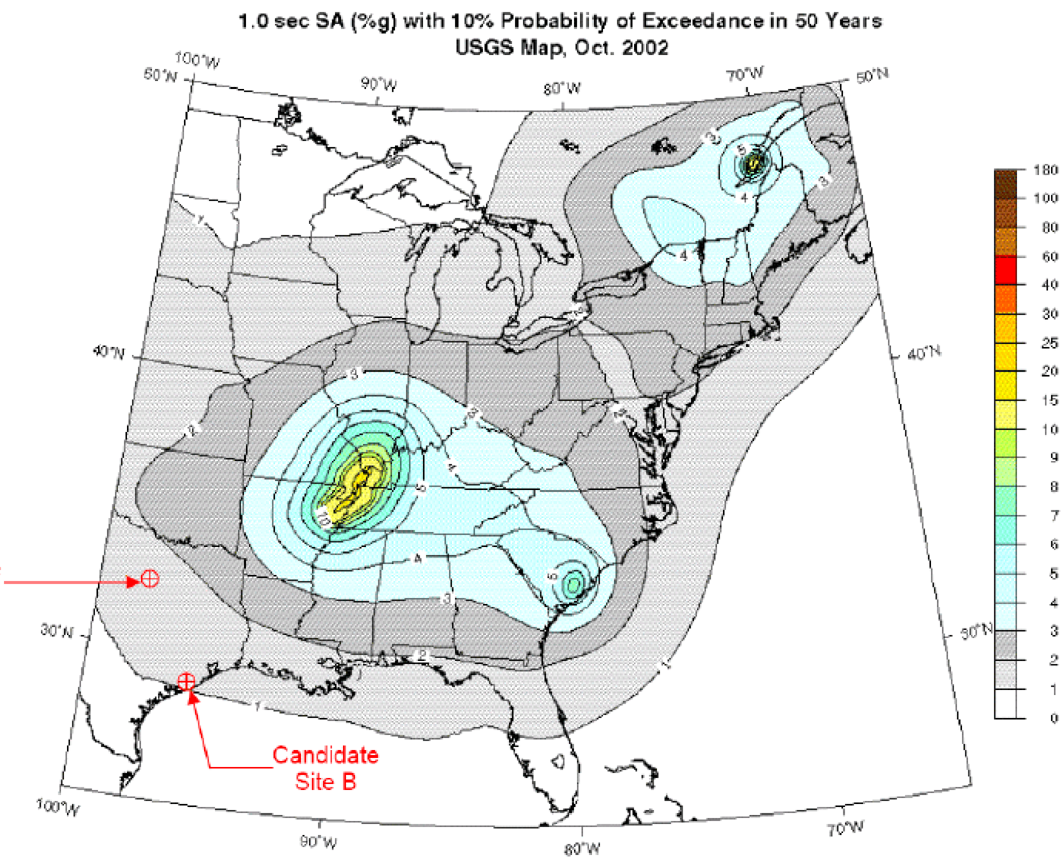


Figure 2B-17. 1.0 sec Spectral Acceleration (%g) with 10% Probability of Exceedance in 50 Years
(Source: USGS National Seismic Hazard Mapping Project 2002 http://eqhazmaps.usgs.gov/html/ceus2002.html)

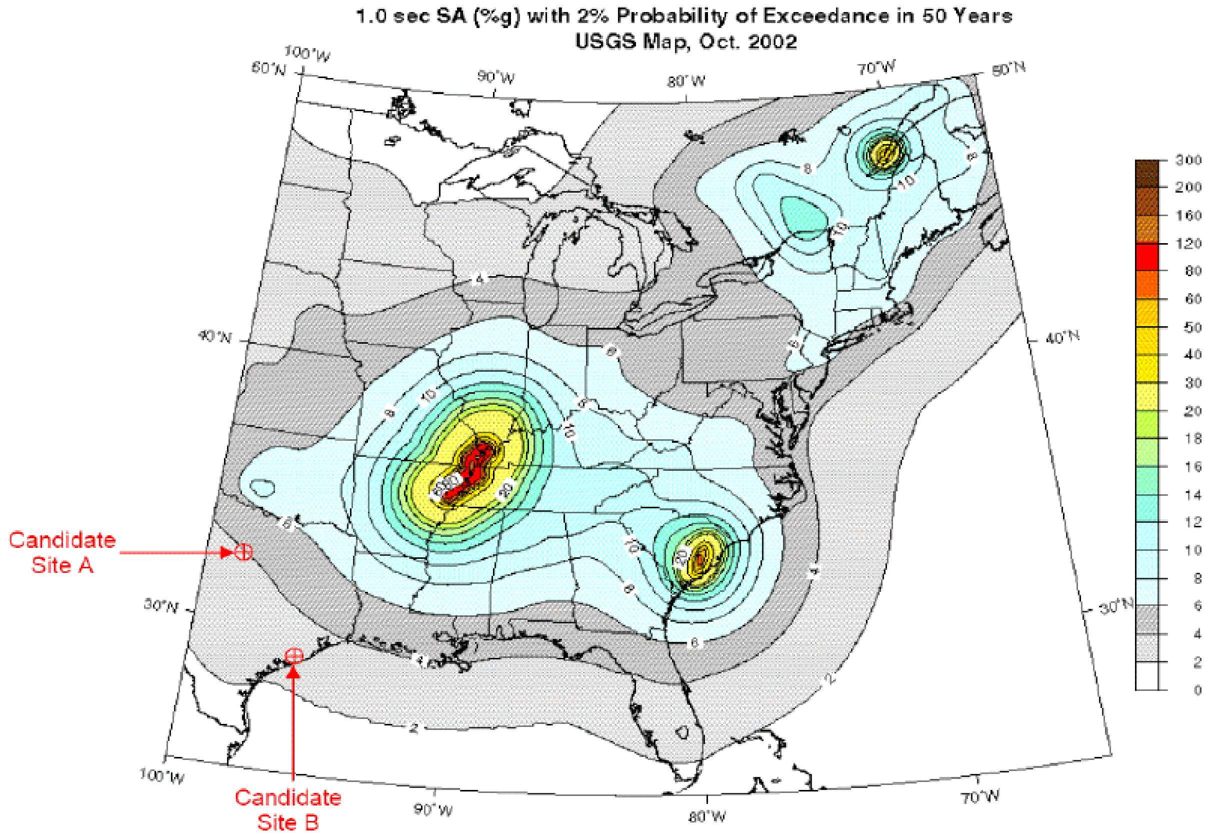


Figure 2B-18. 1.0 sec Spectral Acceleration (%g) with 2% Probability of Exceedance in 50 Years
(Source: USGS National Seismic Hazard Mapping Project 2002 http://eqhazmaps.usgs.gov/html/ceus2002.html)

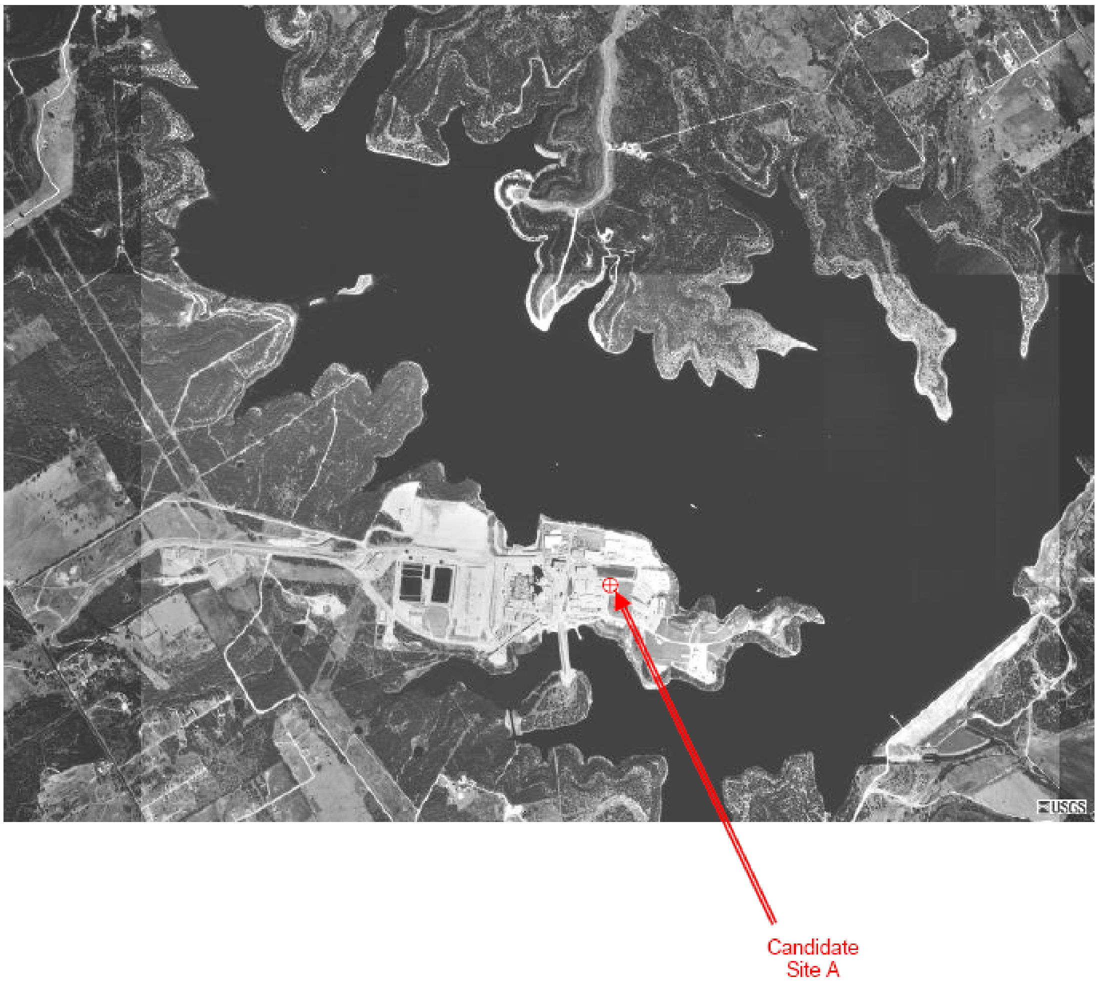


Figure 2B-19. Aerial Photo - Candidate A Site *(Source: USGS and Microsoft Research http://www.terraserver-usa.com, February 2, 1995)*

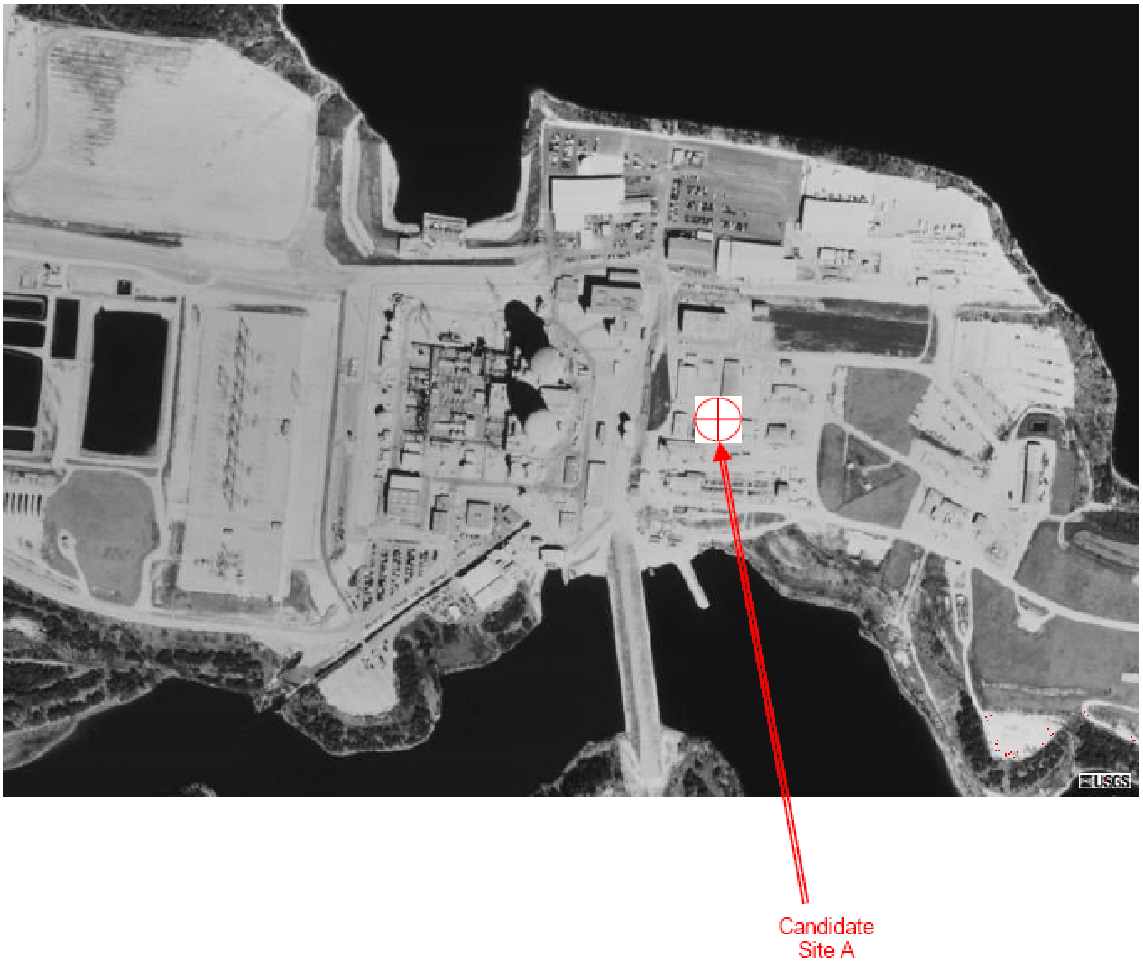


Figure 2B-20. Aerial Photo - Candidate Site A *(Source: USGS and Microsoft Research http://www.terraserver-usa.com , February 2, 1995)*

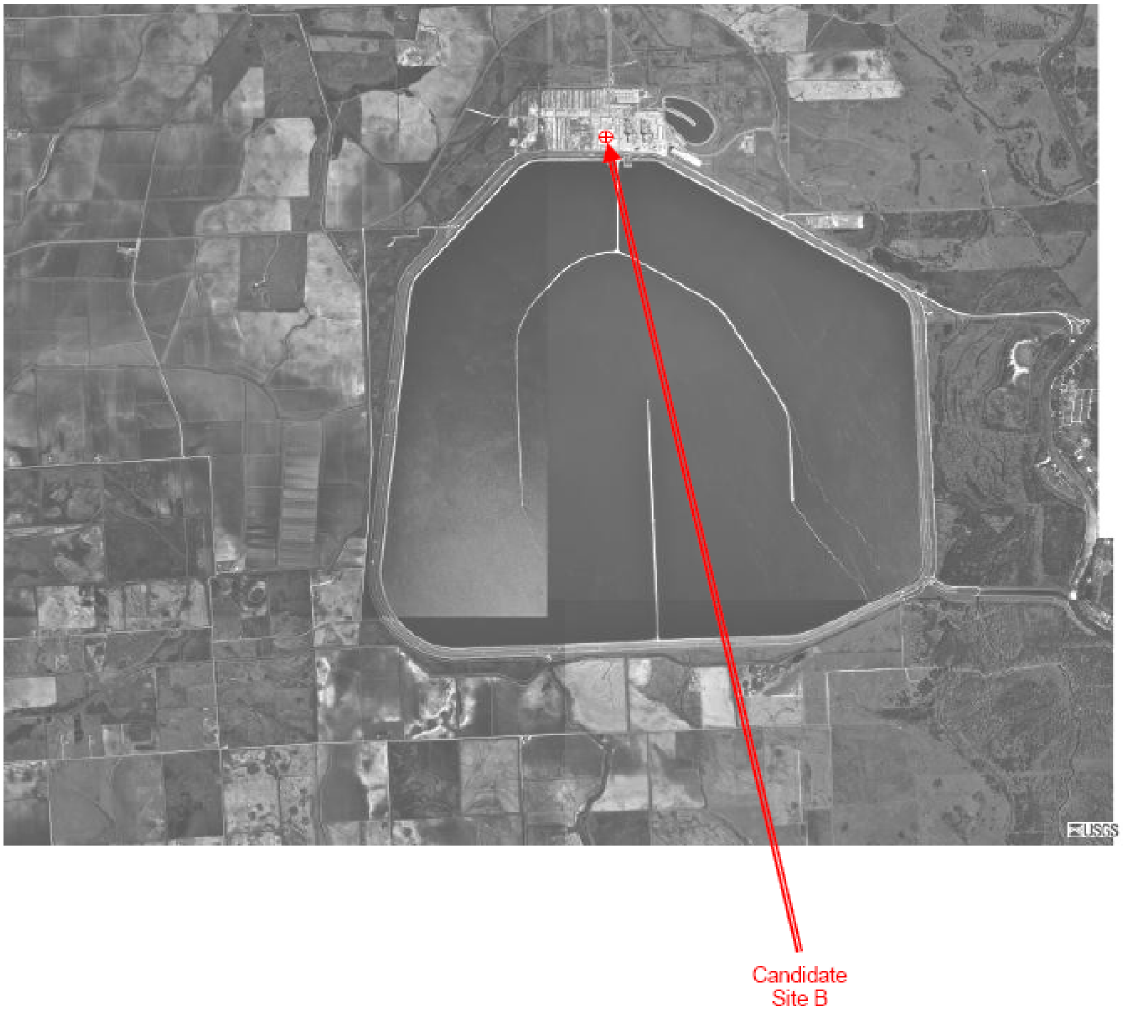


Figure 2B-21. Aerial Photo - Candidate Site B *(Source: USGS and Microsoft Research http://www.terraserver-usa.com February 4, 1995)*

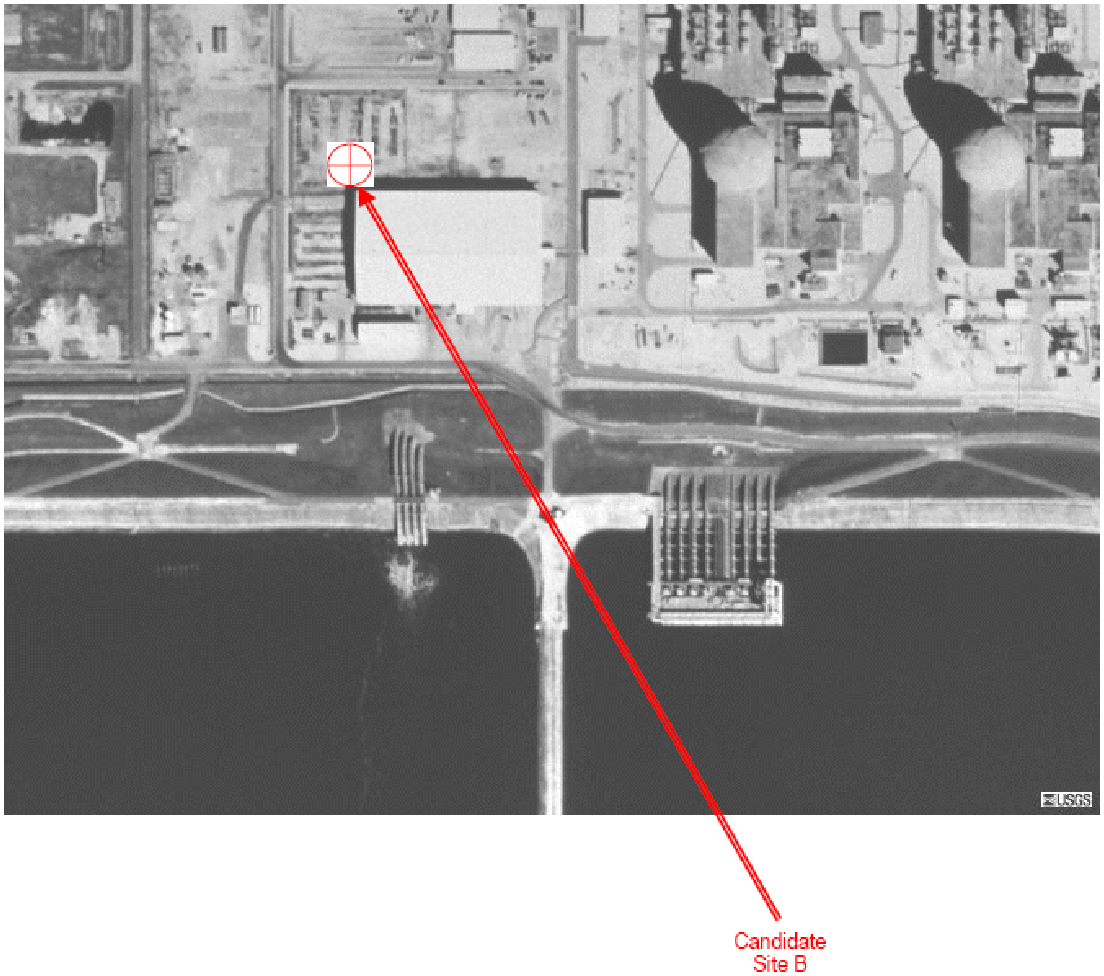


Figure 2B-22. Aerial Photo - Candidate Site B*(Source: USGS and Microsoft Research http://www.terraserver-usa.com February 4, 1995)*

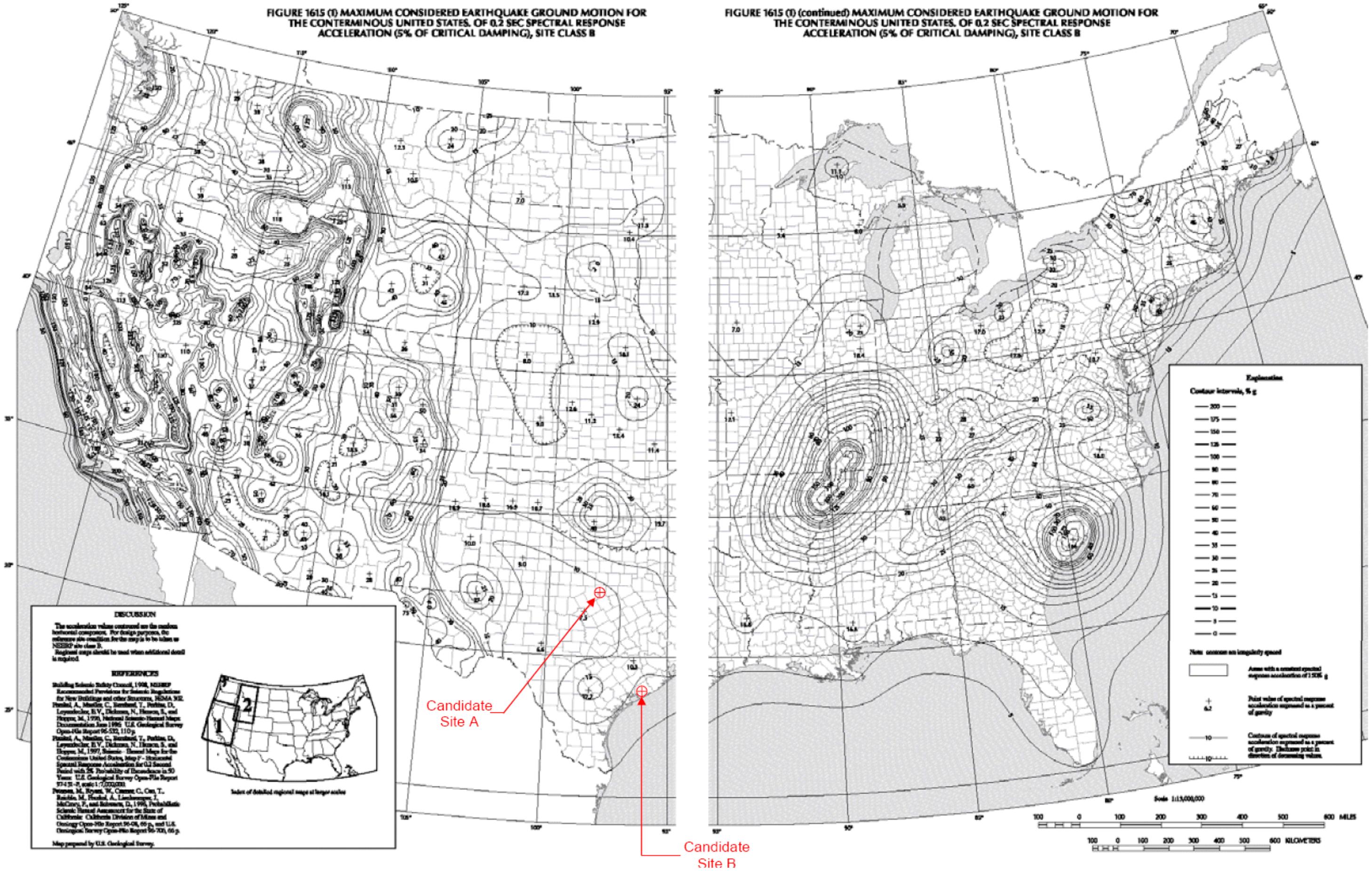


Figure 2B-23. IBC Ground Motion for the Conterminous United States - 0.2 sec period Spectral Acceleration (5% of critical damping), Site Class B *(Source: USGS 2003 International Building Code (IBC) Maps http://eqhazmaps.usgs.gov/html/ibc_maps.html)*

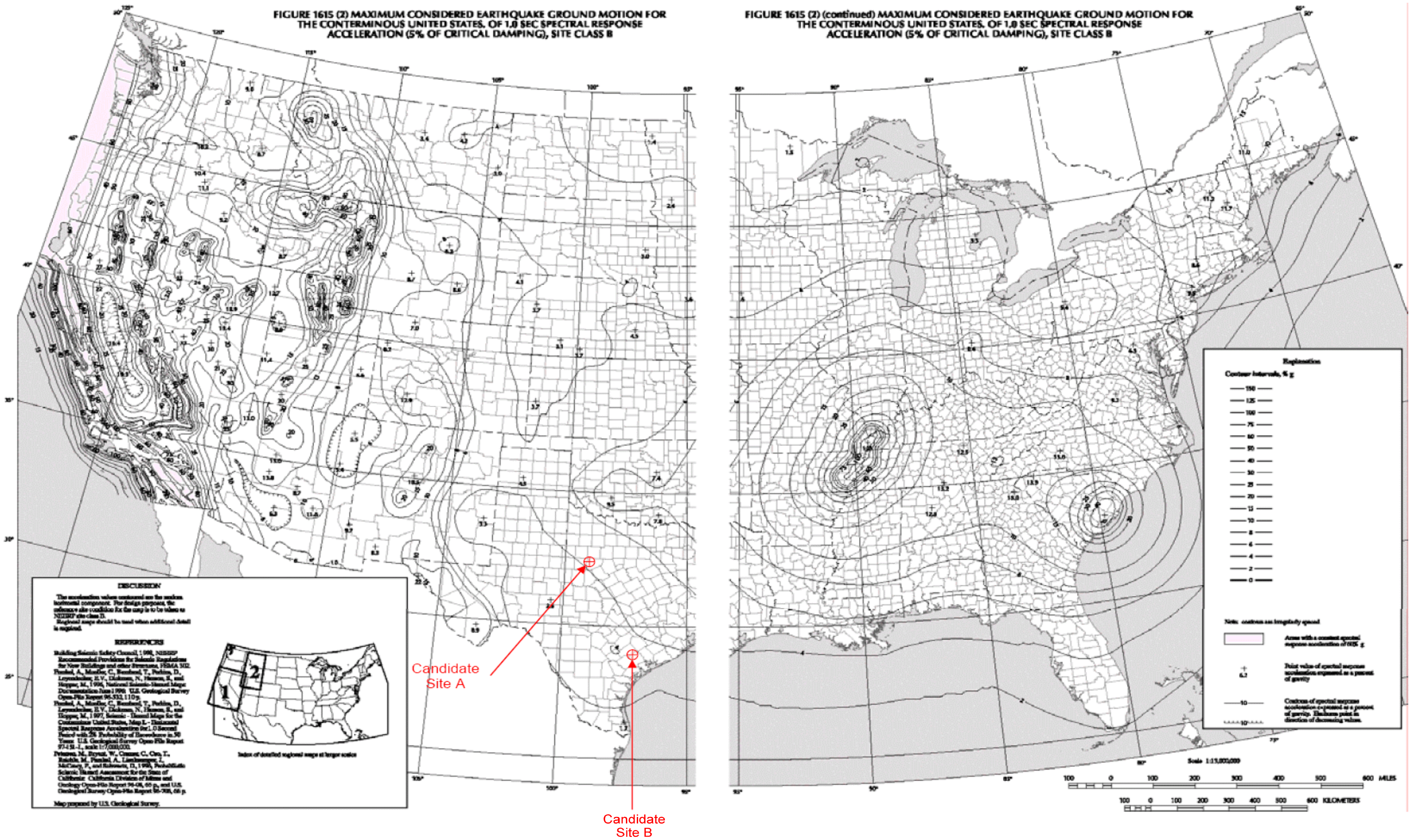


Figure 2B-24. IBC Ground Motion for the Conterminous United States - 1.0 sec period Spectral Acceleration (5% of critical damping), Site Class B *(Source: USGS 2003 International Building Code (IBC) Maps http://eqhazmaps.usgs.gov/html/ibc_maps.html)*

Figure 2B-25. Brazos River Valley Basin (Western Portion, see inset)

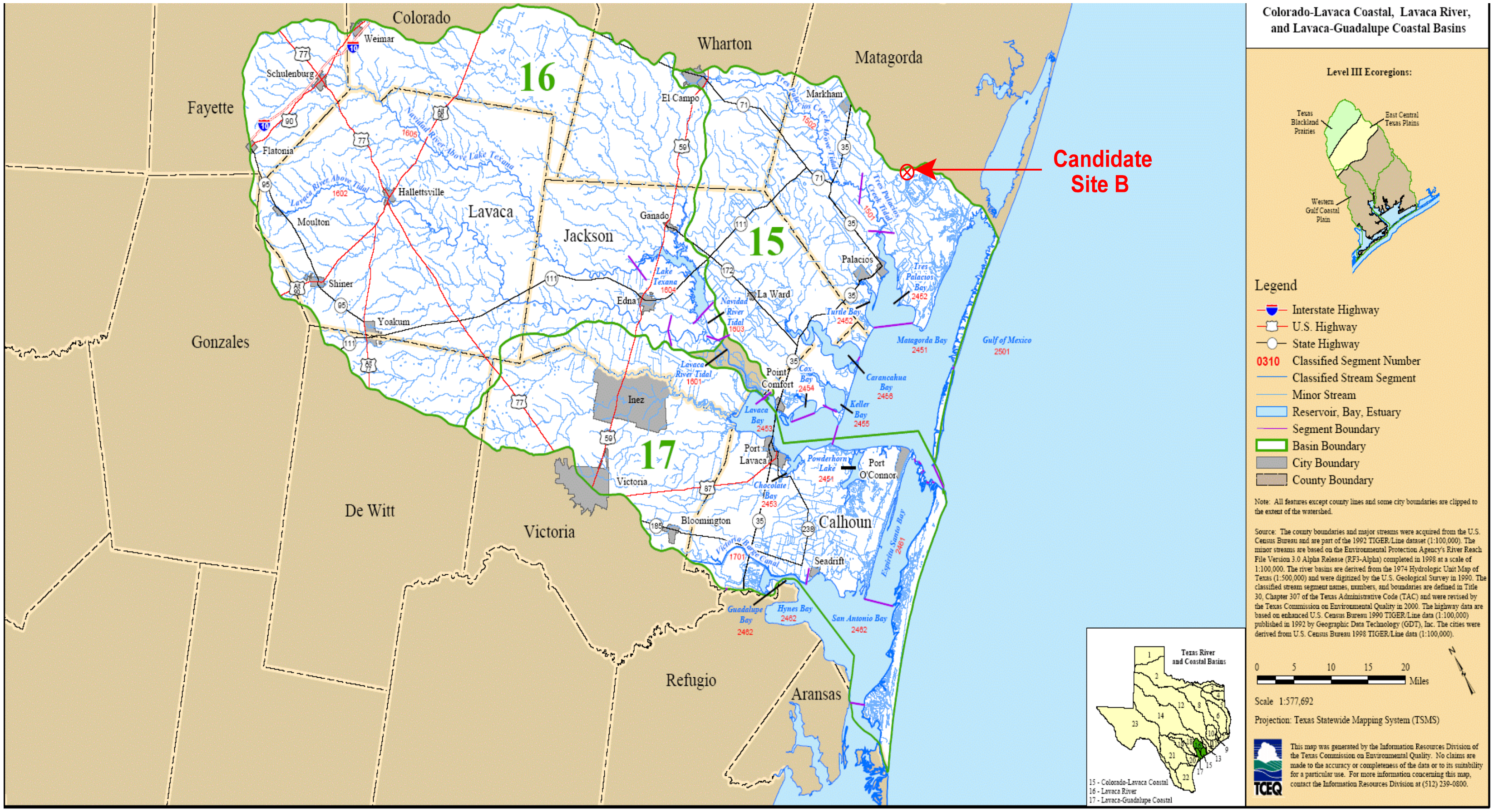


Figure 2B-26. Colorado-Lavaca Coastal, Lavaca River, and Lavaca-Guadalupe Coastal Basin *(Source: Texas Commission on Environmental Quality http://www.tceq.state.tx.us/comm_exec/forms_pubs/pubs/gi/gi-316/index.html)*

APPENDIX 2C. ENVIRONMENTAL SUITABILITY CRITERIA
(TAKEN FROM THE EPRI SITING GUIDE)

Criteria to Determine the Environmental Suitability of Sites with Existing Nuclear Power Plants

		STEPS			
Section	**Criteria**	**1**	**2**	**3**	**4**
3.1	Health and Safety Criteria				
3.1.1	Accident Cause-Related				
3.1.1.1	Geology/seismology (GEOL)				
3.1.1.1.1	Vibrator Ground Motion	E	E	S	S
3.1.1.1.2	Capable Faults	E&A	E&A	S	S
3.1.1.1.3	Surface Faulting and Deformation	A	A	S	S
3.1.1.1.4	Geologic Hazards	A	A	S	S
3.1.1.1.5	Soil Stability		A	A&S	S
3.1.1.2	Cooling System Requirements				
3.1.1.2.1	Cooling Water Supply (HYDRO)	A	A	S	S
3.1.1.2.2	Ambient Temperature Requirements (MET(	E			
3.1.1.3	Flooding (HYDRO)	E	E	S	S
3.1.1.4	Nearby Hazardous Land Uses (LU, SOCEC)				
3.1.1.4.1	Existing Facilities		A	S	S
3.1.4.2	Projected Facilities			S	
3.1.1.5	Extreme Weather Conditions (MET)				
3.1.1.5.1	Winds	E&A		S	
3.1.1.5.2	Rainfall	E&A			
3.1.2	Accident Effects-Related				
3.1.2.1	Population (DEM)	E	E	S	S
3.1.2.2	Emergency Planning (DEM, LU, SOCEC)			S	S
3.1.2.3	Atmospheric Dispersion (MET)	E	E	S	
3.1.3	Operational Effects - Related				

		STEPS			
Section	**Criteria**	**1**	**2**	**3**	**4**
3.1.3.1	Surface Water - Radionuclide pathway				
3.1.3.1.1	Dilution Capacity			S	S
3.1.3.1.2	Baseline Loadings			S	S
3.1.3.1.3	Proximity to Consumptive Users			S	
3.1.3.2	Groundwater Radionuclide Pathway (HYDRO & RAD)	A	A	S	S
3.1.3.3	Air Radionuclide Pathway (MET, RAD)				
3.1.3.3.1	Topographic Effects			S	S
3.1.3.3.2	Atmospheric Dispersion	E	E	S	
3. 1.3.4	Air-Food Ingestion Pathway (MET, RAD, LU)			S	
3.1.3.5	Surface Water-Food Radionuclide Pathway (HYDRO, RAD & LU)			S	S
3.1.3.6	Transportation Safety (MET, LU)			S	
3.2	Environmental Criteria				
3.2.1	Construction-Related Effects on Aquatic Ecology				
3.2.1.1	Disruption of Important Species/Habitats (ECOL)	E	A	S	S
3.2.1.2	Bottom Sediment Disruption Effects (HYDRO)				
3.2.1.2.1	Contamination			S	S
3.2.1.2.2	Grain Size			S	S
3.2.2	Construction-Related Effects on Terrestrial Ecology				
3.2.2.1	Disruption of Important Species/Habitats and Wetlands (ECOL)				
3.2.2.1.1	Important Species/Habitats			S	S
3.2.2.1.2	Ground Cover/Habitat			S	S
3.2.2.1.3	Wetlands	E	E	S	S

		STEPS			
Section	**Criteria**	**1**	**2**	**3**	**4**
3.2.2.2	Dewatering Effects of Adjacent Wetlands (ECOL)				
3.2.2.2.1	Depth of Water Table			A&S	S
3.2.2.2.2	Proximal Wetlands			S	S
3.2.3.	Operational-Related Effects on Aquatic Ecology				
3.2.3.1	Thermal Discharge Effects (ECOL & HYDRO)				
3.2.3.1.1	Migratory Species Effects			S	S
3.2.3.1.2	Disruption of Important Species/Habitats			S	S
3.2.3.1.3	Water Quality			S	S
3.2.3.2	Entrainment/Impingement Effects (ECOL & HYDRO)				
3.2.3.2.1.	Entrainment Organisms			S	S
3.2.3.3	Dredging/Disposal Effects (LU & HYDRO)				
3.2.3.3.1	Upstream Contamination Sources			S	S
3.2.3.3.2	Sedimentation Rates			S	S
3.2.4	Operation-Related Effects on Terrestrial Ecology				
3.2.4.1	Drift Effects on Surrounding Areas (ECOL)				
3.2.4.1.1	Important Species/Habitat Areas			S	S
3.2.4.1.2	Source Water Suitability			S	S
3.3	Socioeconomic Criteria				
3.3.1	Socio economics-Construction-Related Effects (LU & SOCEC)			S	S
3.3.2	Socio economics-Operation				S
3.3.3	Environmental Justice			S	S
3.3.4	Land Use				
3.3.4.1	Construction and Operation-Related Effects	E	E&A	S	S

		STEPS			
Section	**Criteria**	**1**	**2**	**3**	**4**
3.4	Engineering & Cost - Related Criteria				
3.4.1	Health and Safety-Related Criteria				
3.4.1.1	Water Supply (HYDRO)			S	S
3.4.1.2	Pumping Distance (ENG)	A	A	S	S
3.4.1.3	Flooding (HYDRO)			S	S
3.4.1.4	Vibratory Ground Motion (GEOL)				
3.4.1.5	Soil Stability (GEOL)			S	S
3.4.1.6	Industrial Site Remediation			S	S
3.4.2	Transportation or Transmission-Related Criteria (LU & ENG)				
3.4.2.1	Railroad Access			S	S
3.4.2.2	Highway Access			S	S
3.4.2.3	Barge Access			S	S
3.4.2.4	Transmission Cost and Market Price Differentials				
3.4.2.4.1	Transmission-Construction			S	
3.4.2.4.2	Electricity Market Price Differentials			S	S
3.4.3	Related to Socioeconomic - Land Use (LU & SOCEC)				
3.4.3.1	Topography (ENG)	E	A	S	S
3.4.3.2	Land Rights (LU)			S	S
3.4.3.3	Labor Rates (ENG-COST)			S	S

Key:
E = Exclusionary A = Avoidance S = Suitability
DEM = Demography ECOL = Ecology GEOL = Geology
HYDRO = Hydrology LU = Land Use MET = Meteorology
SOCEC = Socioeconomics ENG = Engineering

APPENDIX 2D. EMERGENCY PLANNING ZONES

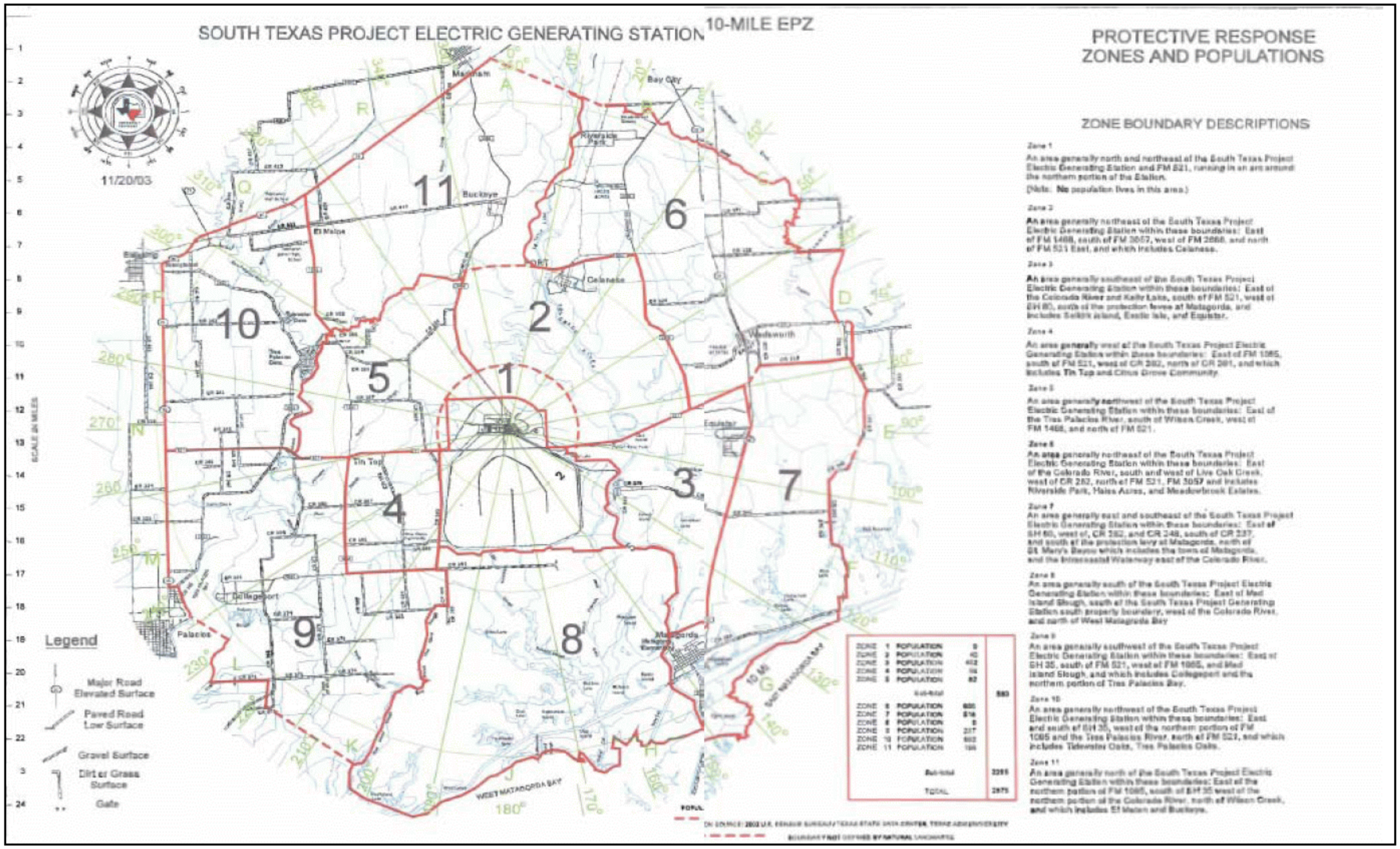


Figure 2D-1. Emergency Planning Zones, South Texas Project.

APPENDIX 2E. EXCLUSION AREA MAPS

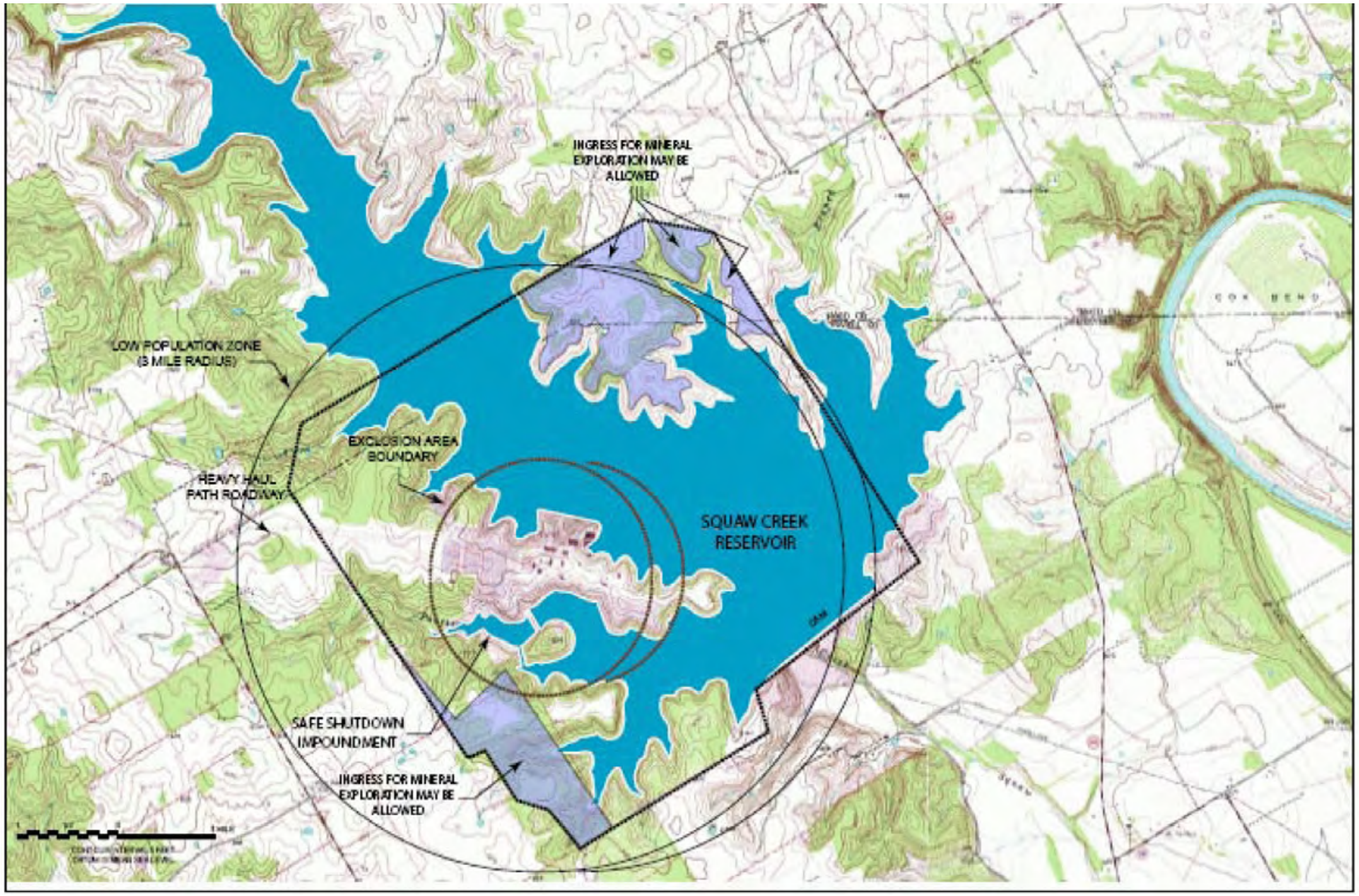


Figure 2E-1. Exclusion Area for Existing Units at Comanche Peak

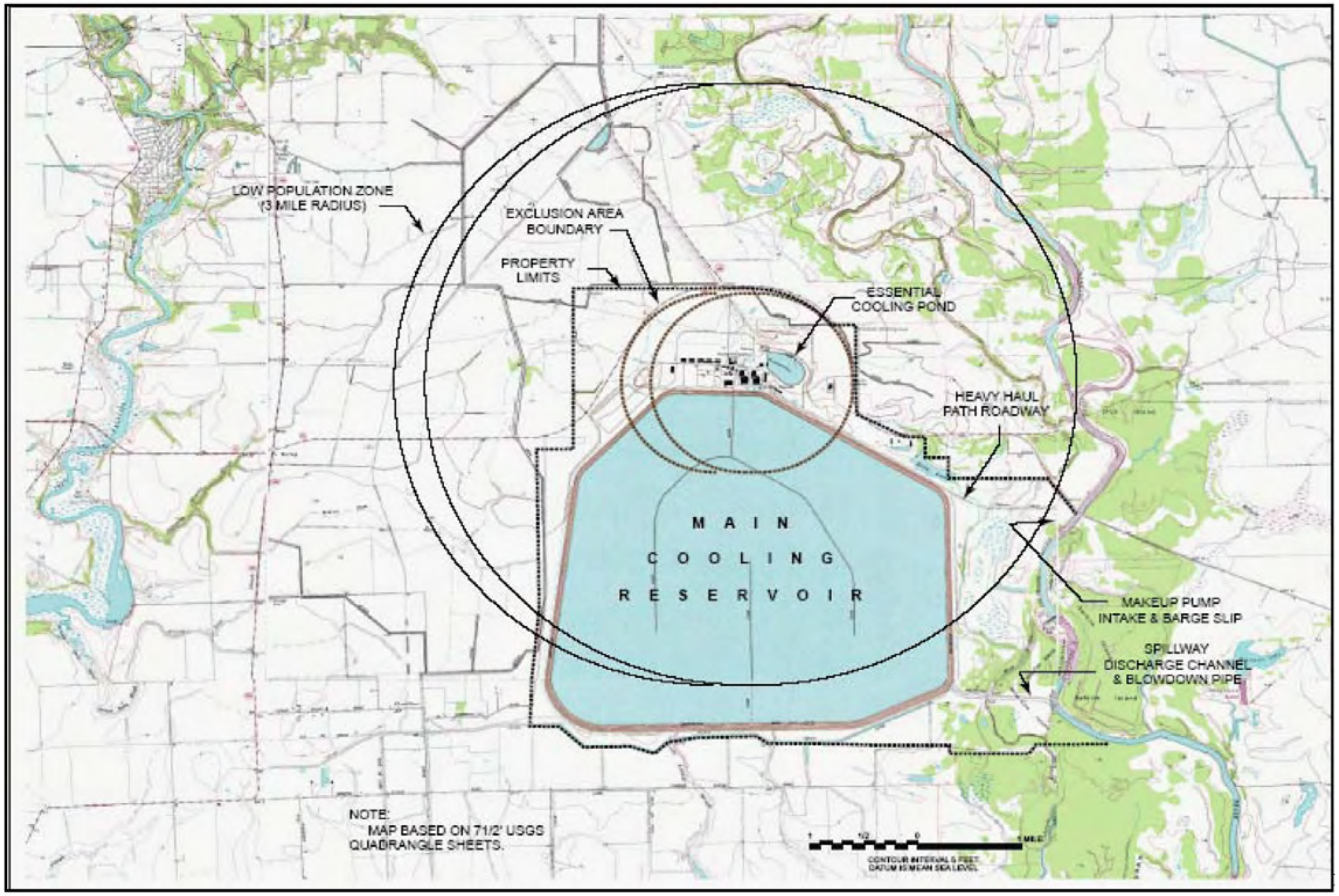


Figure 2E-2. Exclusion for Existing Units at South Texas Project.

APPENDIX 2F. CONCEPTUAL SITE LAYOUTS

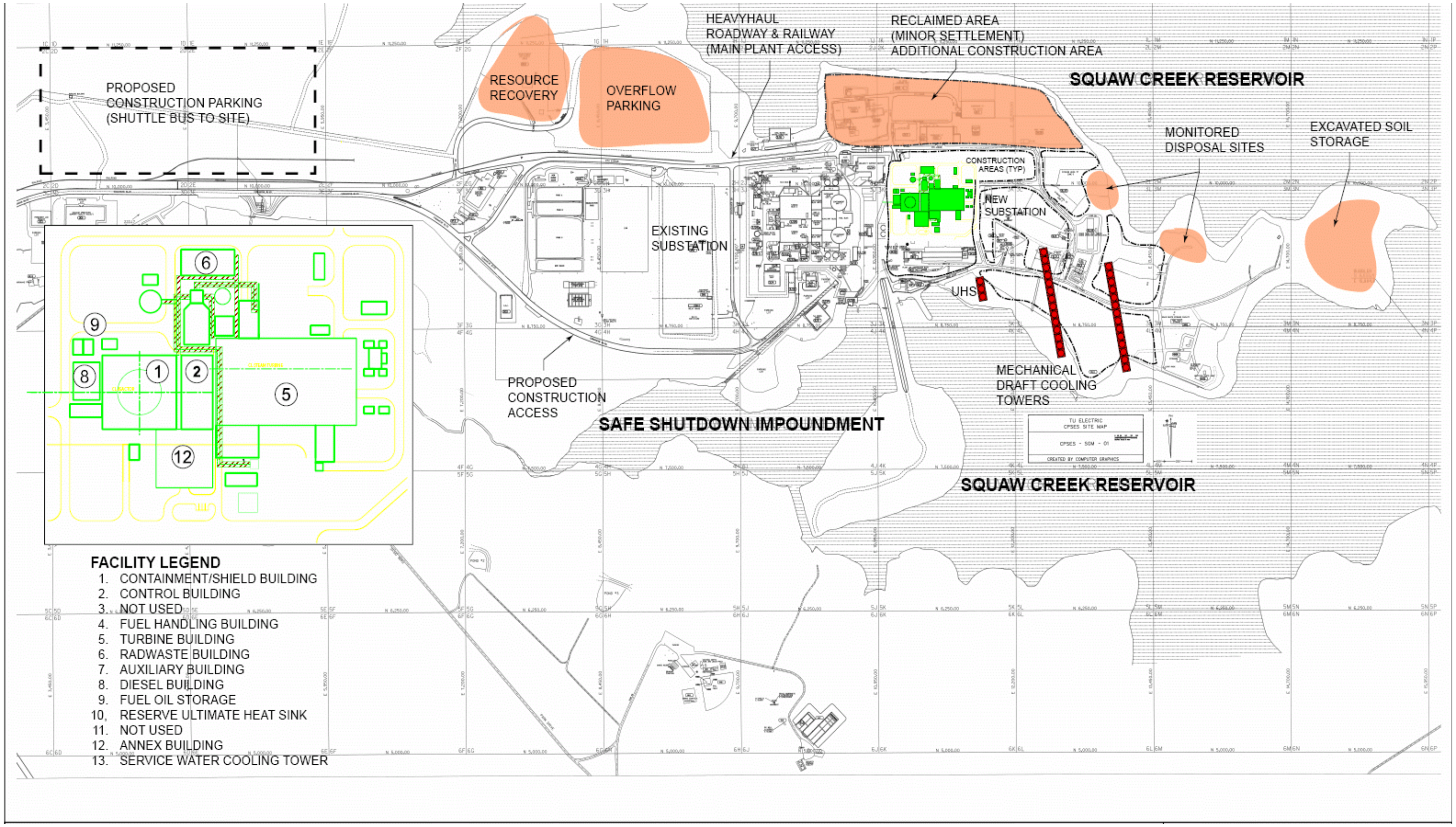


Figure 2F-1. Conceptual Site Layout of a Single Unit ABWR at Comanche Peak

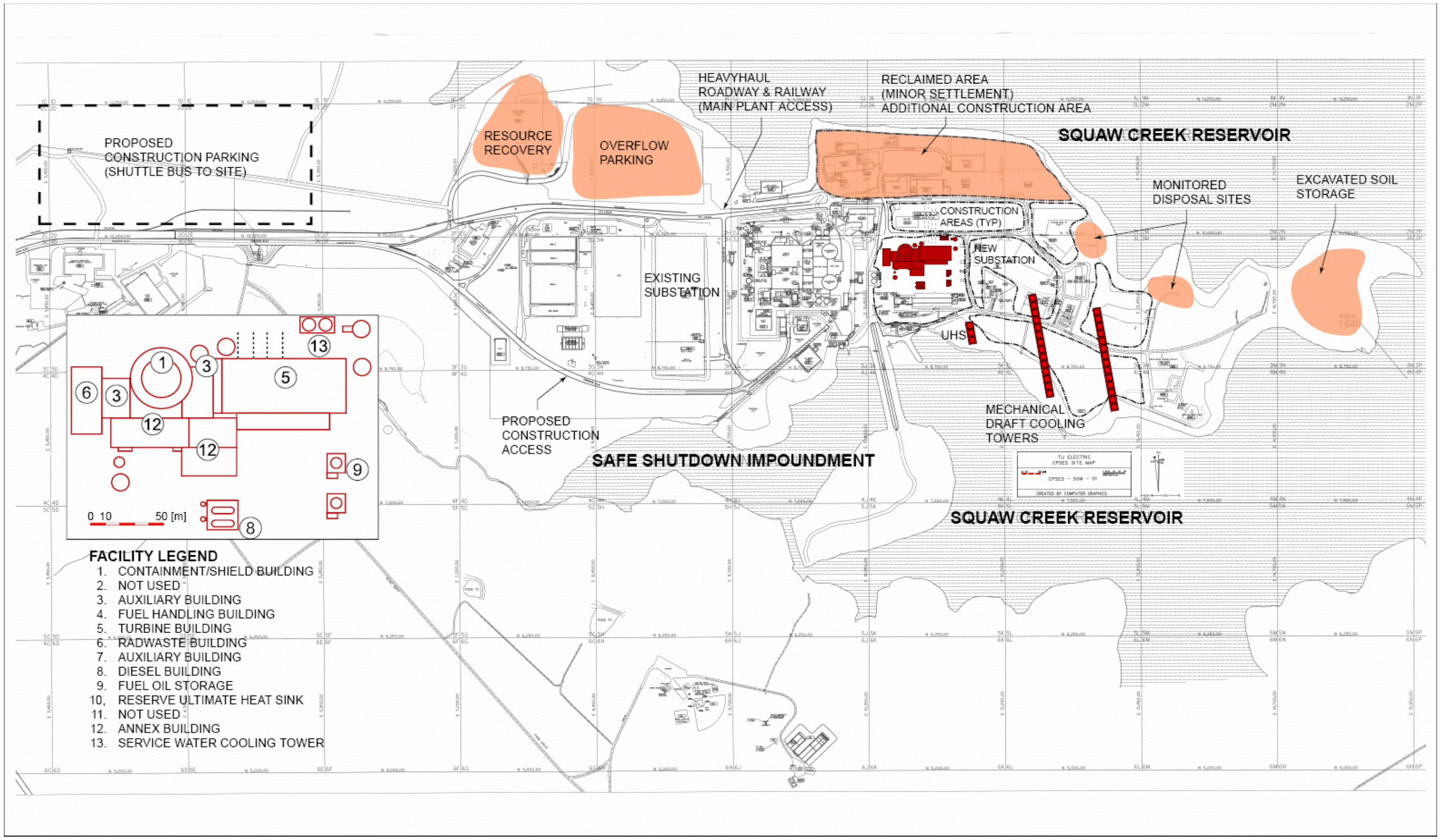


Figure 2F-2. Conceptual Site Layout of a Single Unit AP1000 at Comanche Peak

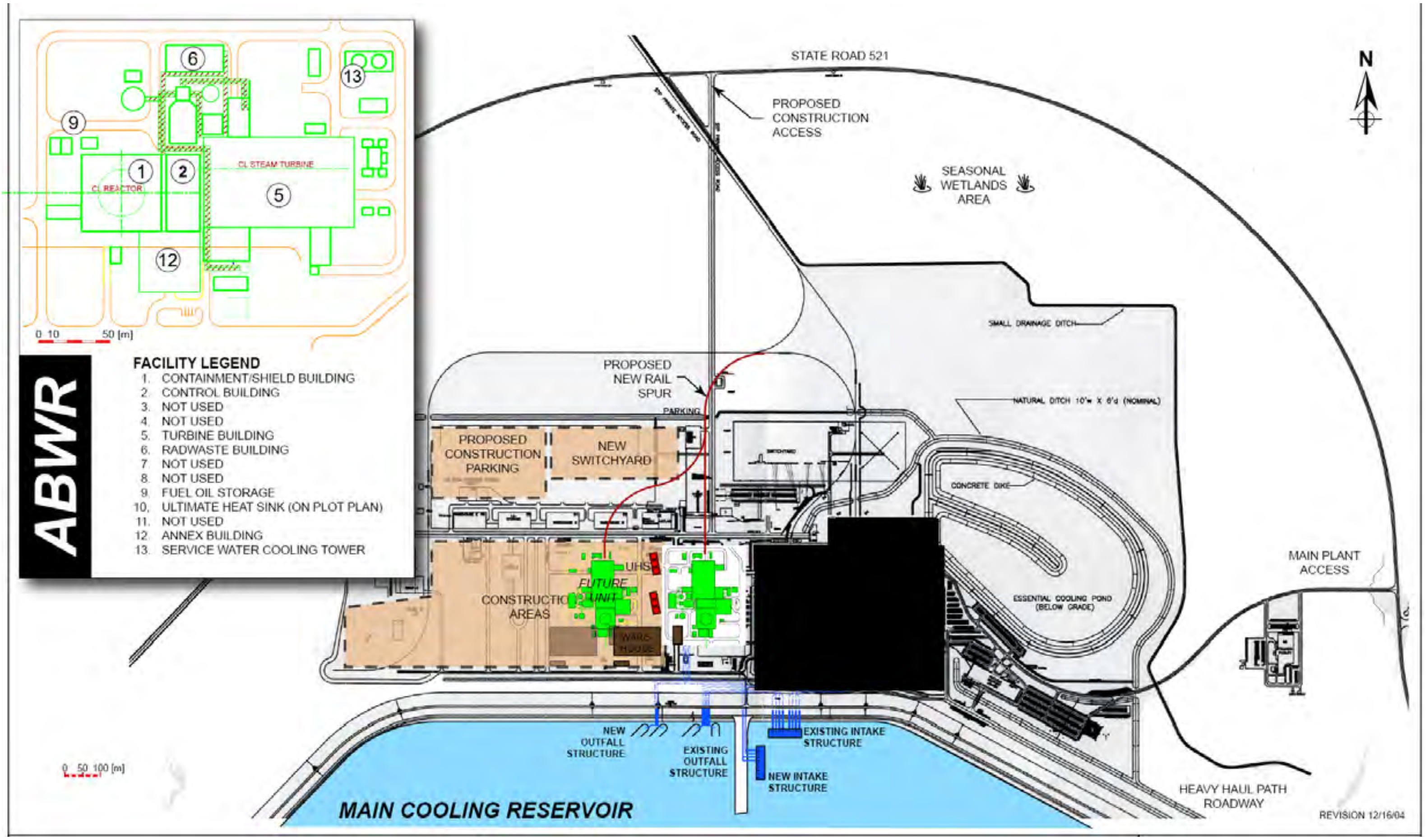


Figure 2F-3. Conceptual Site Layout of a Single Unit ABWR at South Texas Project.

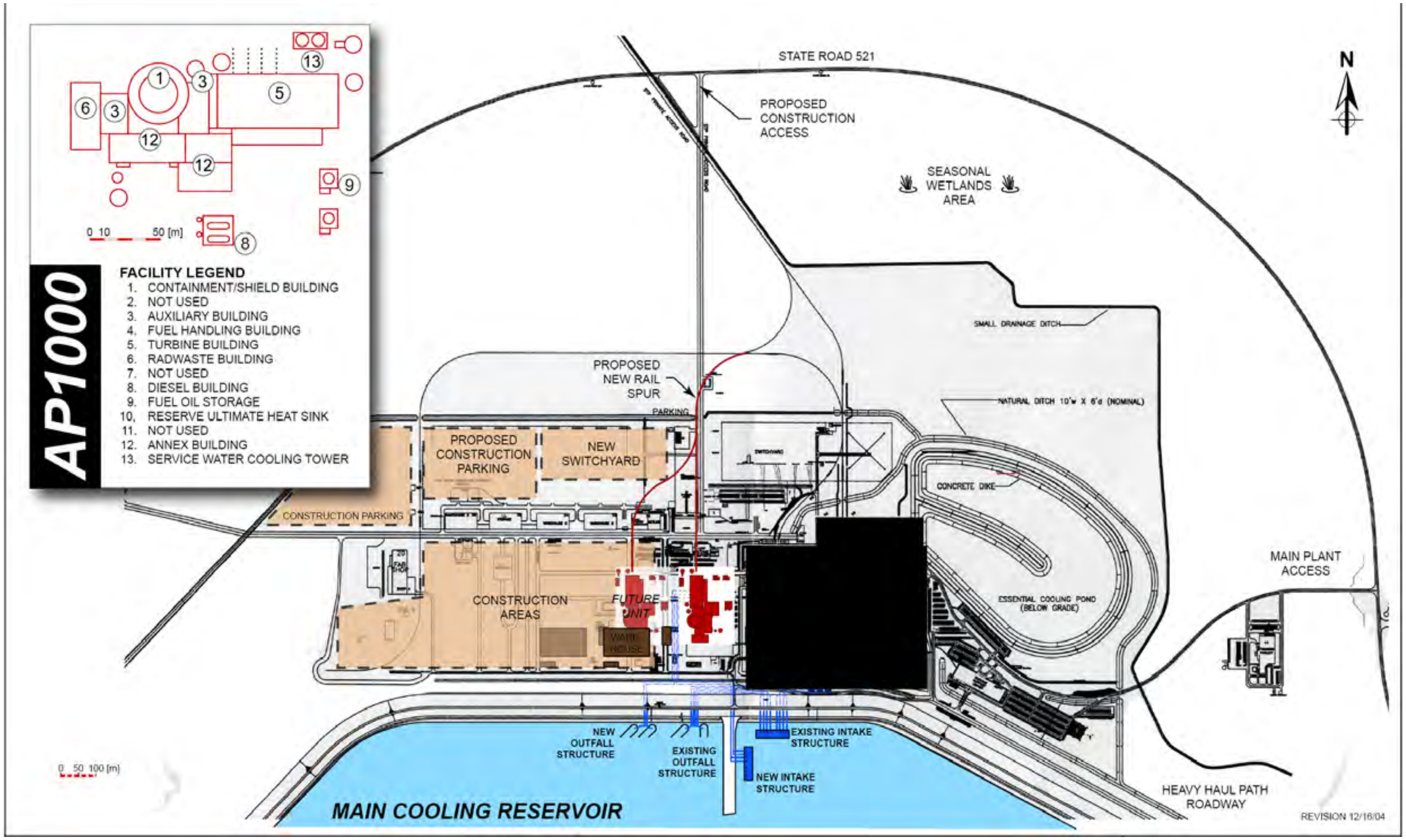


Figure 2F-4. Conceptual Site Layout of a Single Unit AP1000 at South Texas Project

APPENDIX 2G. ERCOT SYSTEM

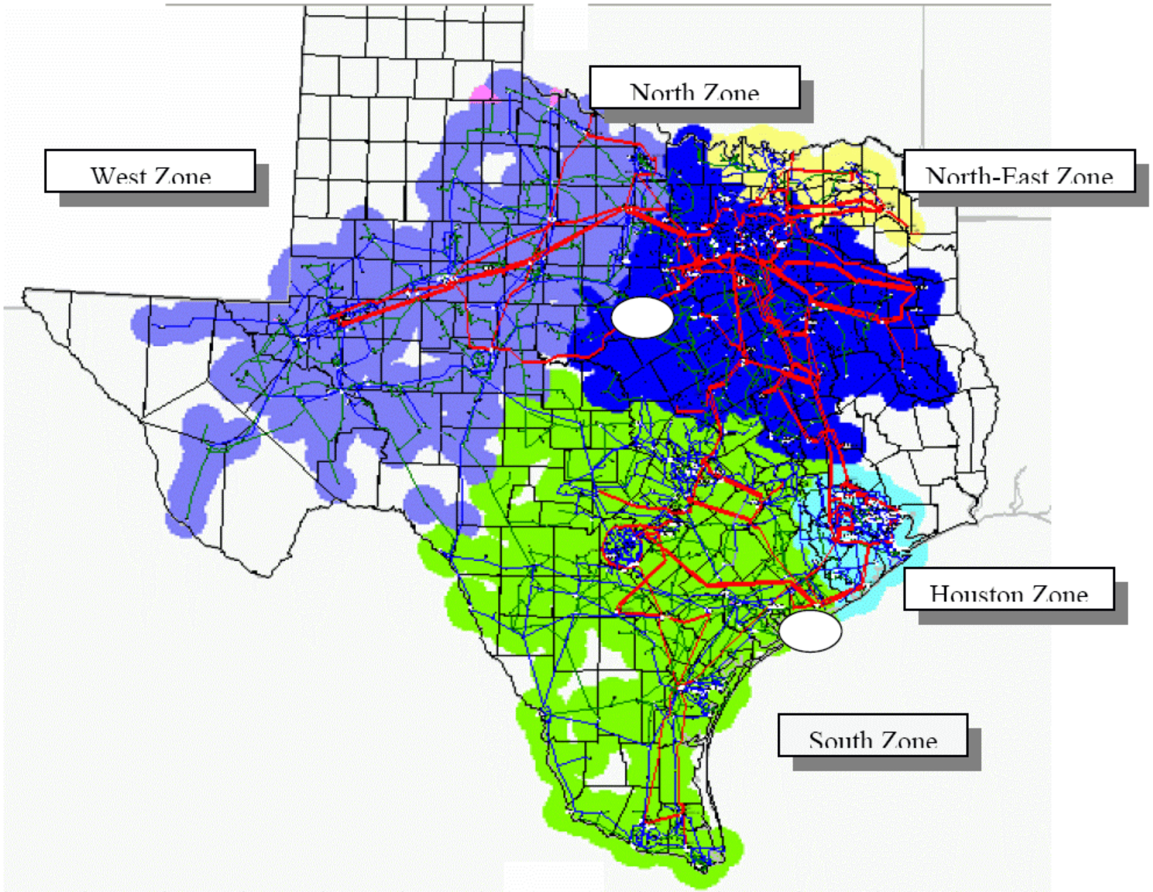


Figure 2G-1. ERCOT Transmission System and Congestion Management Zones

APPENDIX 2H. TECHNICAL INFORMATION ON THE ACCR CONDUCTOR

2H-1. THE FOLLOWING INFORMATION WAS CULLED FROM MAGAZINE ARTICLES:

The new Aluminum Composite Conductor Reinforced (ACCR), an overhead power conductor that doubles the electrical transmission capacity of conventional conductors of the same diameter, will receive its first commercial application early next year, when Xcel Energy (Minneapolis, Minnesota, U.S.) installs the ACCR on a 10-mile (16-km) transmission line in the Twin Cities region.

Xcel Energy is using the conductor to increase the capacity of a transmission line that extends from Shakopee to Burnsville. The upgrade is part of a U.S. $100 million expansion project at the utility's Blue Lake “peaking” plant in Shakopee, which is needed to ensure a reliable supply of power to Xcel Energy's customers in the Upper Midwest during periods of peak electricity demand.

The ACCR is intended as a solution to thermally constrained transmission bottlenecks that have increasingly plagued electricity grids in recent years, causing brownouts and blackouts.

The product has been extensively tested in the laboratory and field-tested for the past four years, including at Oak Ridge National Laboratory in Tennessee, under the auspices of the U.S. Department of Energy, and at locations operated by Xcel Energy, Western Area Power Administration (in North Dakota and Arizona) sites, the Salt River Project, Hawaiian Electric Co. and Bonneville Power Administration at a site in Washington state. The power line has been proven under a broad range of extreme conditions, such as saltwater corrosion, high winds, vibration, and extreme heat and cold.

Known as aluminum conductor composite reinforced (ACCR), the 795-kcmil conductor's core consists of aluminum-matrix composite wires to carry high tensions with low sag characteristics, surrounded by aluminum zirconium wires that can withstand higher operating temperatures. This design allows the conductor to carry significantly more current than today's 795-kcmil aluminum conductor steel reinforced (ACSR) wire.

The new technology could offer many benefits for utilities. Perhaps most significantly, installation of the smaller 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.

2H-2. MATERIAL PROPERTIES

The Composite Conductor is a non-homogeneous conductor consisting of high-temperature aluminum-zirconium strands covering a stranded core of fiber-reinforced composite wires. Both the composite core and the outer aluminum-zirconium (Al-Zr) strands contribute to the overall conductor strength.

TASK 3 APPENDIX

APPENDIX 3A. CTQ ANALYSIS METHODOLOGY

This appendix includes a detailed summary of the process used to link the ‘end user’ and ‘investor’ CTQs with the nuclear technology options under evaluation. Key to this process is the development of the CTQs themselves and the search for evaluation criteria (including measurable metrics) which have a strong correlation to the CTQs.

The end user CTQs were developed as part of Task 1 as originally planned. That plan included an assumption that a significant percentage of a perspective new plant would be owned by the end users. During the process of completing that task it was recognized that additional investors would likely be required for this or similar projects. As a result, a new investor CTQ task activity was added to the scope. This activity included the selection of draft CTQs by the study team with validation by the investor community planned as part of Task 6.

These CTQs were not formally applied to the hydrogen generation and desalination evaluation activities.

The list of end user CTQs (from Task 1) and draft investor CTQs follows:

End User CTQs	**Investor CTQs**
Low Cost	Return on invested capital (ROIC)
Cost stability	Bond holder investment horizon
Few service interruptions	NRC financial policy for nuclear plants
High power quality	Value predictability
Flexibility to meet load profile	Minimum development cost
Less usage of natural gas	Debt/Equity ratio
Predictable start of supply	Manage unique risks
Supplier portfolio	Public acceptance
Air emissions offsets	Certainty of COL & Construction Costs
	Waste issue resolution
	Long power purchase agreement
	Strong customer financials

Next, a list of more detailed and directly measurable evaluation criteria was developed to use as a basis for direct correlation to the CTQs. This list was reduced to the ‘top ten’ criteria with a team selection process. Sandia, TIACT, and EnergyPath participated in this activity which resulted in the selection of following “top ten’ criteria. The number following each criteria title is its rank.

Top 10 Correlation Criteria

EPC Cost(4)
Capital Cost Uncertainty (6)
Financing Cost (1)
Design Operational Experience (2)
U.S. Design License (3)
Recent Project Experience (8)
Plant Design Maturity (10)
Construction Schedule (9)
Project Schedule (7)
Licensibility (5)

Although the number of members of the correlation selection team was statistically small (nine), the relative strength of criteria rank and standard deviation are reported in the figure below. They are deemed potentially meaningful only in a relative sense.

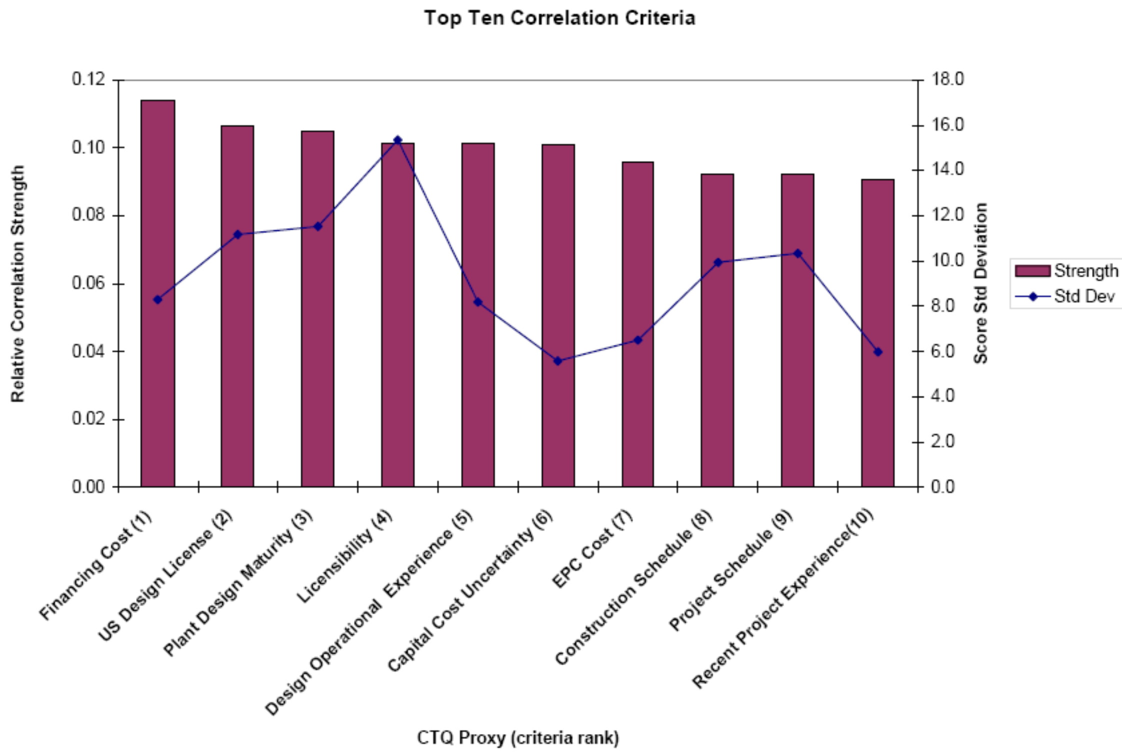


Figure 3A-1. Top 10 Correlation Criteria

Figure 3A-1 reveals that 'financing cost' and 'design operational experience' were the top ranked criteria. This indicates that the task team selected these two criteria as having the highest correlation with the CTQs (all CTQs as weighted by end user and investor selected weight factors).

Having determined the top ten correlation criteria, the next step was to develop metrics or proxy measurement values that could be used to measure the ability of each technology to fulfill a criterion. Thus, each design is "measured" and "scored" for each of the top ten criteria. As an example, Design Operational Experience is scored with a range of 1 to 5 where a score of "1" indicates a design with no prototype operational experience and a score of "5" indicates a design having greater than 10 reactor years of operational experience. The scores of 2 through 4 are also assigned relative definitions.

This scoring method is applied to all the design options for each correlation criteria. The results of this activity are illustrated in Figure 3A-2 below. Note that the "scores" have been normalized.

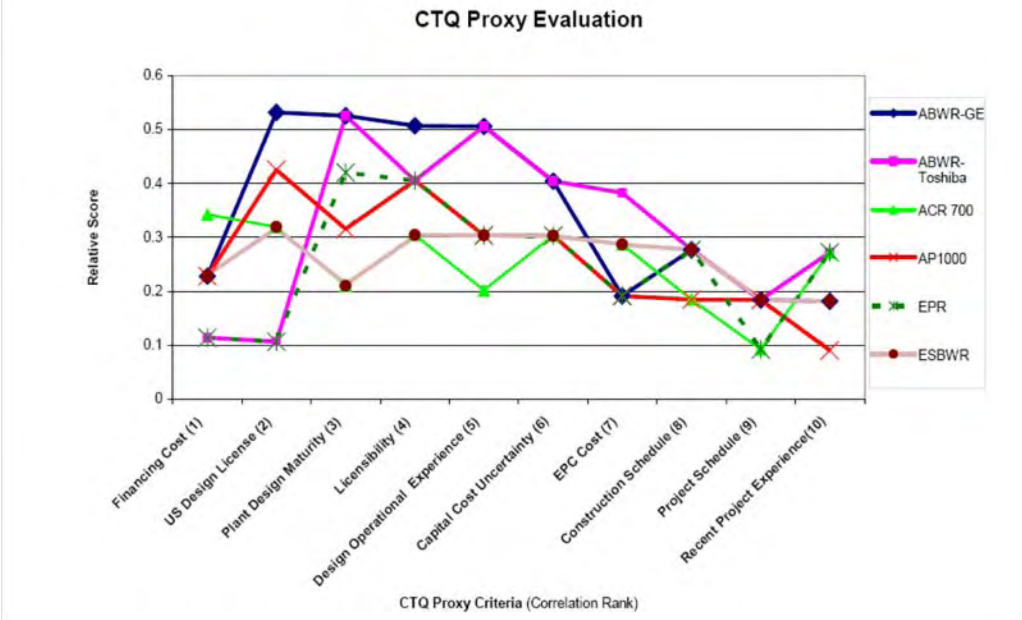


Figure 3A-2. CTQ Proxy (Top Ten) Evaluation

Next, the total scores for each technology design were calculated by summing the design specific weighted scores for all criteria. After normalizing the totals, the results obtained are shown in Figure 3A-3 below as the integrated evaluation summary.

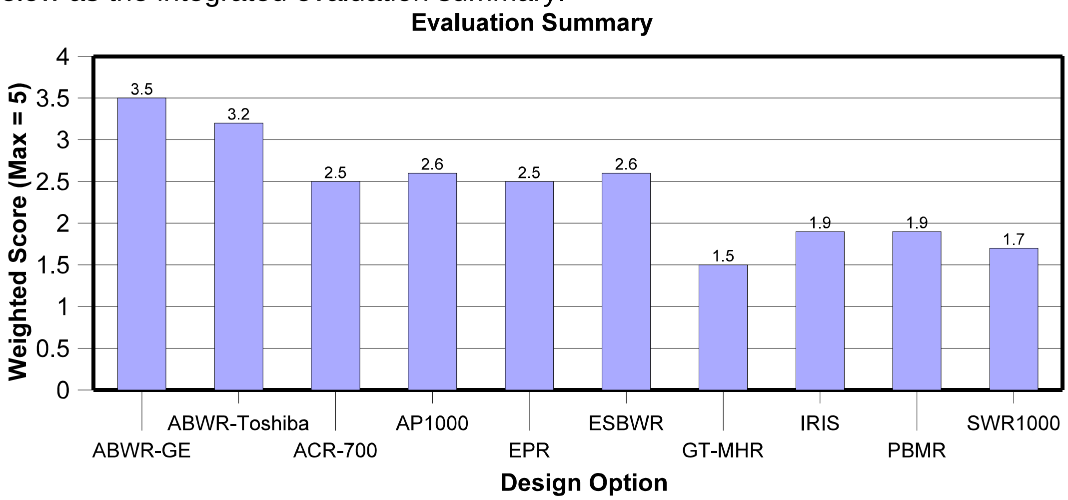


Figure 3A-3. Integrated Evaluation Summary (Relative Ability to Fulfill CTQs)

The following sample charts are provided as additional supporting documentation. Given their total size, they are presented here as partial charts intended only to illustrate the process used. Individual responses within these charts should be considered as representative.

Table 3A-1 is a sample worksheet format that was used to obtain team member inputs (i.e., votes) indicating their perspectives on the strength of correlation between the 2nd tier subset criteria list (35 items) and each of the end user and investor CTQs.

Table 3A-1. Sample CTQ vs Criteria Correlation Worksheet

Task 3 CTQ vs Criteria Correlation Worksheet

Evaluation Criteria → / CTQs ↓ (Scoring: 1-10)	Expanded Definition/ metric concept	Weighting Factor	Land requirements	Uncertainty in Capital Cost	Staff Exposure	High Level Waste Generation	Low level Waste Generation	EPC Cost	Financing Cost	Fuel Cost	O&M Cost	Recent Project Experience	Supplier Co...
END USER CTQs													
Low cost	$/MwHr Delivered		5	7	1	4	3	9	7	7	8	4	3
Cost stability	low $/Mwhr volitility		1	8	2	3	3	4	3	7	7	3	4
Few Service Interruptions	<.2/yr Forced Outage Rate		1		1							3	4
High Power Quality	stable voltage performance		1	1								1	
Flexibility to meet load profile	Low cost top & trim		1	3		1	1	2	2	5	5	2	1
Less usage of natural gas	10% in Texas by 2010		3	4	1	2	1	5	5	5	5	2	2
Predictable start of supply	no. months delayed		1	8	1	1	1	4	3	3	2	6	4
Supplier portfolio	Ability to deliver/credit worthiness		1	6	1	1	1	4	6	6	6	4	5
Air emission offsets	create new value ASAP		1	4	1	1	1	5	5	3	3	2	2
Subtotal	Unweighted		15	41	8	13	11	33	31	36	36	27	25
INVESTOR CTQs													
return on invested capital ROIC	>15% Returns in excess of WACC		3	7	1	2	2	9	9	7	7	2	2
Bond Holder Investment Horizon	10-15 years			6				6	6	6	6	1	3
NRC Financal Policy for Nuclear Plants	Who can own it			1	1	1	1	1	3	1	1	1	3
Value Predictability	0.2 Coef of Variation			9	1	1	1	6	4	5	5	3	2
Predictable CO Date	< 5 years +/- 6 months			4	1	1	1	3	3	2	2	8	5
Short construction Period	<30 months		5	4	1	1	1	2	2	1	1	5	4
Minimum Development cost	Not to exceed option value		5	5	1	1	1	2	2	2	2	4	2
Debt/Equity Ratio	80/20		1	3	1	1	1	6	3	3	3	6	5
Manage Unique Risks	Prob of extended shutdown<1%/yr		3	2	2	2	2	2	2	4	3	5	4
Subtotal	**Unweighted**		17	41	9	10	10	37	34	31	30	35	30
Total Score (Unweighted)			32	82	17	23	21	70	65	67	66	62	55

Table 3A-2 is a partial look at the base supplier input worksheet format. This was used as data input template. It contains greater than 150 criteria input opportunities.

Table3A-2. Design Evaluation Data Input Table (Partial)

NP 2010 Texas Gulf Coast Nuclear Power Plant Feasibility Study

Task 3: Technology Assessment
Evaluation Data Table (Rev 3 EnergyPath Corporation)

				Supplier/Design ====>	PBMR		Westinghouse/AP 1000	
Top Tier		Sub Tier 1	Sub Tier 2	Metric Unit(s)	Input Data or Value	Comments	Input Data or Value	Comments
A. Top Level Plant Specs								
A.	1	Net Electric Output		MWe	165-172 MWe / module for all-electric mode	Multi-module configurations available; 8 pack arrangement @ 1376 MWe max depending on Heat Sink conditions [Note: compare Efficiency definitions]	1117	
A.	2	Total Thermal Energy		MWth	400 MWt /module		3415	
A.	3	Design Type and designator		text	VHTR - Direct Brayton Cycle PBMR (Pebble Bed Modular Reactor)	Note: The PBMR meets the Generation IV VHTR criteria	PWR - AP1000	two loop design
A.	4	Primary Heat Transfer Medium		text	Helium		Light water	
A.	5	Primary System Temp		Degrees C	900	Target: Uncertain until demonstrated	301	
A.	6	Primary System Pressure		PSI	9 Mpa / 1305 psi	Pressure can be optimized for primary application	2250	
A.	7	Base Hydrogen Gen Technology (if applicable)		text	All	WEC Hybrid Cycle has been assessed at PBMR conditions; PBMR, as process heat source, will couple to all H2 processes; no restrictions. Likely outside desired time horizon on current development tract.		input provided separately; reports by Goosen and Lahaoda
A.	8	Base Desalination Technology (if applicable)		text	All; Evaporative assessed at 13,000 m3 per day per module	Evaporative Cycle has been assessed at PBMR conditions; PBMR, as process heat source, will couple to all processes; no restrictions		no data provided
B. Plant Design Data								
B.	1	Land requirements (min/nominal)		ft^2	10,000 M2 footprint	See LWR vs. 8 multi-module footprints, 400 M Radius EPZ	1,090,000	Single unit with cooling tower
B.	2	Buildings Required (number/footprint/ total volume)			3	Module building, Service building and water intake building. See module building space functions		
B.	2		a Nuclear Island	# / ft^2 / ft^3	na	PBMR Direct Cycle requires only one module building;	1/32,800/ 5,700,000	
B.	2		b Turbine Island	# / ft^2 / ft^3	na		1/46,000/ 6,800,000	
B.	2		c Balance of Plant	# / ft^2 / ft^3	na		3/43,000/ 2,100,000	
B.	3	Plot plan layout		drawing		See multi-module plot plan	APP-0000-X2-011	
B.	4	Plant Design Lifetime		years	40-60	40 nominal, 60 Extended [Note: dependent on ASME Code Cases and/or advanced material use] Uncertain until proven.	60	

APPENDIX 3B. HYDROGEN PRODUCTION FROM NUCLEAR ENERGY

3B-1. EXECUTIVE SUMMARY*

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 and production of hydrogen in the U.S. 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. The production of hydrogen is currently based on fossil fuel sources – 95% comes from steam-methane reforming. The energy equivalent of the present hydrogen production rate is 100 GWth (about thirty 3000-MWth reactors). 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 U.S. 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 electrical production.

The technical challenges and the investment required to meet these projected market demands are significant. Storage, distribution and application technologies must be developed to implement hydrogen use on a large scale, but the transition to that state can be accelerated by the development of large scale nuclear hydrogen production capabilities for near-term large-scale applications. In the long term, economics and national policy will determine the mix of energy sources that are implemented, and the technologies initially implemented may differ from those ultimately selected for long-term deployment. In any scenario, domestically based, emission-free energy sources will be high priority candidates for further development. Among these primary energy sources, nuclear energy offers great potential for the large-scale production of hydrogen.

Research is currently underway in many countries to investigate the potential for all of the practical energy sources for hydrogen production, including:

- Fossil sources with carbon sequestration (coal and natural gas)
- Renewable energy sources (solar, wind, and hydroelectric)
- Biological methods biomass and biological), and
- Nuclear energy.

Nuclear energy can be used to produce hydrogen from both fossil fuel feedstocks and from water by several methods, including:

- Nuclear assisted steam reforming/coal gasification
- Conventional electrolysis
- High temperature electrolysis
- Thermochemical cycles
- Hybrid Thermochemical/Thermoelectric cycles.

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* Paul S. Pickard, Ronald J. Lipinski, and Tara M. Pandya**; Sandia National Laboratories, Albuquerque, NM 87185; **presently at Texas A&M, College Station, TX.

Research on the advanced methods is at an early stage, and it is anticipated that commercial demonstrations are a decade or more away. DOE is planning a commercial demonstration of nuclear hydrogen in the 2017 to 2020 time frame. In the near term, conventional electrolysis is the most likely technology for emissions free nuclear hydrogen production.

One kilogram of hydrogen is approximately equal to a gallon of gasoline in energy content, so to be competitive with gasoline for an internal combustion engine, hydrogen needs to be around 2 $/kg or less (assuming gasoline remains heavily taxed and hydrogen is not). But a fuel cell in an electric car is more efficient, so for that application hydrogen could be competitive at 3 $/kg or more. Steam-methane reforming (SMR) is presently the least expensive way to produce hydrogen in large quantities. Hydrogen from SMR (including capital recovery cost, operating costs, etc.) is approximately 1.0 $/kg when natural gas costs 3.00 $/MBtu. Hydrogen from SMR is sensitive to the cost of natural gas and is about 2.50$/kg when natural gas is 8 $/MBtu.

For conventional electrolysis, the cost is dominated by the cost of electricity. Existing units can produce hydrogen with a total system efficiency (or “wallplug efficiency) of 50% to 78%. A currently available large capacity system operates with an efficiency of 73%. At this efficiency hydrogen is produced at a rate of 53 kWh/kg. So if electricity costs 0.04 $/kWh, then hydrogen will cost a bit over 2.12 $/kg for the electrical energy, resulting in a cost of hydrogen from a plant using grid electricity of about 2.50 to 3.00 $/kg, depending on financial and operational assumptions. Additional costs to the user will include distribution costs.

There are numerous companies that offer commercial products that make hydrogen by electrolysis. The table below lists the major companies along with descriptions of the process they use and the peak production rate of their largest unit. The wallplug efficiencies include all the electrical power needed to run the system and will be discussed in a later section. The largest available unit provides 43.6 kg/h at 73% wallplug efficiency. A small city with 100,000 cars used for 12,000 mi/y would require at least 54,000 kg/day of hydrogen (at 60 mi/kg using fuel cells). This in turn would require 2250 kg/h and 120 MW of electricity at 73% system efficiency if production were 24 hours per day.

Table 3B-1. List of Companies Offering Hydrogen-Producing Electrolyzers Available

Company	Address	Type[bc]	Max H_2 Rate (kg/h)[de]	System Power (kWe)	Wallplug Efficy.
Air Products	www.air_products.com	alk	10.8	840	50%
Avalence	www.avalence.com	alk, uni	0.4	25	70%
ELT Elektrolyse Technik	www.elektrolyse.de/vkp/index.php	alk, bi	30	1498	78%
Fideris, Inc.	www.fideris.com	n.a.	n.a.	n.a.	n.a.
Gaskatel	www.gaskatel.com	alk, bi	n.a.	n.a.	n.a.
Giner, Inc.	www.ginerine.com	PEM	3.6	n.a.	n.a.
H_2-Interpower	www.h2-interpower.de	PEM	0.072	n.a.	n.a.
Hamilton Sundstand	www.hsssi.com/applications/echem/hydrogen	PEM	5.8	315	72%
Hydrogenics Corporation	www.hydrogenics.com	PEM	2.7	3.8	70%
Japan Storage Battery Co., Ltd.		PEM	0.180	n.a.	n.a.
Linde Gas Company	www.linde-gas.com			n.a.	n.a.
Norsk Hydro Electrolysers AS	www.electrolysers.com	alk, bi	43.6	2328	73%
Proton Energy Systems, Inc.	www.protonenergy.com	PEM	0.5	37.8	56%
Siam Waterflame Co., Ltd.	www.waterflame.co.th/	alk	0.027	n.a.	n.a.
Stuart Energy Systems Corp.	www.stuartenergy.com	alk, bi	10.9	576	73%
Teledyne Energy Systems	www.teledyneenergysystems.com	alk,bi	13.5	840	63%
Treadwell Corporation	www.treadwellcorp.com	PEM	0.919	n.a.	n.a.

Cost estimates for electrolyzers vary with size of the installation, manufacturer and application, but many studies have projected future estimates of 500 to 1000$/kWe for electrolyzer capital costs at larger sizes. Increase in scale (unit production capacity), increase in the production rate of fuel cells for electric vehicles, and/or reduction in the amount of platinum required per unit area of the electrolyzer membrane could help enable cost reductions. But the capital recovery costs are about four times less than electrical costs, so further reductions in capital cost are important but not essential.

Other more advanced H_2 production systems using process heat have the potential to be even less expensive than electrolysis. These more advanced systems require considerably more research and testing. In addition, they might require siting of the nuclear plant closer to the location where the H_2 would be used if piping costs are significantly more expensive than power line costs (per unit energy delivered).

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b alk = alkaline, uni= unipolar, bi = bipolar, PEM = Proton Exchange Membrane.

c n.a. = not available.

d 1 kg/h = 11.1 NM^3/h (nominal cubic meters per hour) = 185 slpm (standard liters per minute) = 11, 100 (standard liters per hour) = 0.185cc/min (cubic centimeters per minute) = 392 scfs (standard cubic feet per hour) = 0.0094 Mmscfd (million standard cubic feet per day) = 286,000 scfm (standard cubic feet per month) = 24 kg/day = 365kg/y .

e 1 Nm^3/h = 0.0901 kg/hr (kilgrams per hour) = 16.7 slpm = 1000 slph = 0.0167 cc/min = 35.3 scfh = 0.000847 Mmscfd = 25,800 scfm = 24 Nm^3/day = 365 Nm^3/y.

3B-2. Hydrogen and Nuclear Energy

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. Although there is significant interest and research activity focused on developing a future hydrogen economy, where hydrogen is used as the fuel for efficient fuel cell vehicles, such a hydrogen economy will require a significant infrastructure with storage, distribution and production facilities that will take decades to develop. However, there is already a considerable market and production of hydrogen for use in refining lower-grade crude oil to produce gasoline, and in the agricultural industry for use in fertilizer production. The production of hydrogen is currently based on fossil fuel sources – primarily steam-methane reforming. This reforming of one high-quality fuel to another is economically justified because of the value of hydrogen in the petrochemical industry.

The current hydrogen market is large – the energy equivalent of 100 GWh (about thirty 3000-MWh reactors) producing hydrogen at 50 % efficiency. Presently, the vast majority of the hydrogen produced in the U.S. is by processing natural gas. The production plant sizes are large. For example, Axsia Howmar has steam-methane reforming (SMR) plants that produce up to 1800 kg/h (see Figure 3B-1). It is worthwhile noting that these applications in general are not dependent on the development of a hydrogen infrastructure and therefore represent a near term application for large centralized hydrogen production and utilization. In general the demand for hydrogen is increasing at a faster rate than overall energy use, since the grade of crude oil being refined in the US is generally decreasing with time. Other large scale centralized applications, such as power peaking based on hydrogen fuel cells may introduce other near term applications.

Figure 3B-1. Steam-Methane Reforming Plant (Axsia Howmar plant in Sweden)

If we are to consider hydrogen as a long-term solution for energy security and environmental concerns, then large-scale, cost-effective hydrogen production methods must ultimately include options that are not dependent on imported fossil fuels and do not produce carbon emissions. Nuclear energy is a promising option to provide the primary energy source for future large-scale hydrogen production. The production of hydrogen represents a new mission for nuclear energy that is potentially larger than the current mission of emission-free electrical production. The technical challenges and the investment required to achieve these primary goals are significant. Storage, distribution and application technologies must be developed to implement hydrogen use on a large scale, but the transition to that state can be accelerated by the development of large scale nuclear hydrogen production capabilities for these large scale near term applications.

In the long term, economics and national policy will determine the mix of energy sources that are implemented, and the technologies initially implemented may differ from those ultimately selected for long-term deployment. In any scenario, domestically based, emission-free energy sources will be high priority candidates for further development.

Among these primary energy sources, nuclear energy offers great potential for the large-scale production of hydrogen.

3B-2.1. Hydrogen Production Options

Hydrogen is abundant in nature but occurs primarily in stable compounds that require significant energy input to separate the hydrogen component for use as a fuel. Hydrogen is an energy carrier, much like electricity, that requires a primary energy source to produce. Domestic energy sources that do not generate greenhouse gases and have the potential to produce hydrogen cost effectively will be essential components of the long-term energy supply. Research is currently underway in many countries to investigate the potential for all of the practical energy sources for hydrogen production, including:

- Fossil sources with carbon sequestration (coal and natural gas)
- Renewable energy sources (solar, wind, and hydroelectric)
- Biological methods biomass and biological), and
- Nuclear energy.

The most abundant, non-fossil source of hydrogen is water, and most of the production methods being considered for nuclear energy split water molecules using thermal or electrical energy. This decomposition of water requires significant energy input. Assuming no ohmic losses, about 140 megajoules (MJ) is required to produce one kilogram (kg) of hydrogen. (The energy content of 1 kg of hydrogen is 3.1 times the same weight of gasoline and therefore is approximately equal to one gallon of gasoline). To accomplish this with heat (thermolysis) alone requires extreme temperatures of 2500/C or more. Furthermore, current technology to produce hydrogen using radiolysis (the chemical decomposition of water by the action of radiation) does not meet minimum efficiency requirements for large-scale applications.

3B-2.2. Nuclear Hydrogen Production Methods

Nuclear energy can be used to produce hydrogen from both fossil fuel feedstocks and from water via various methods, including:

- Nuclear assisted steam reforming/coal gasification
- Conventional electrolysis

- High temperature electrolysis
- Thermochemical cycles
- Hybrid Thermochemical/Thermoelectric cycles

- **Nuclear assisted steam reforming or coal gasification** utilizes the nuclear heat source to replace the fossil fuels that would be used to provide process heat for the chemical process. About a third of the natural gas used to produce hydrogen in steam-methane reforming is required to produce the high temperature process heat for the reforming process. Although the fossil fuel requirement and CO_2 emissions are reduced, these methods are not considered as important for nuclear energy since they are still dependent on fossil feedstock sources. The cost of hydrogen from steam-methane reforming is dominated by the cost of natural gas.

- **Conventional electrolysis** is the most straightforward technology currently available to produce hydrogen directly from water. Conventional electrolyzers are available with electric to hydrogen conversion efficiencies of over 70% (total, not just in the electrolyzer cell). This gives an overall hydrogen production efficiency of 23 to 28% if electricity generation is 33 to 40% efficient. Electrolyzer cells are presently available from several commercial suppliers in sizes up to 2.4 MW at nominal costs of $1000-$3000 per kW electric for relatively small installations. The cost of hydrogen from conventional electrolysis is dominated by the cost of electricity for large installations.

- **High-temperature electrolysis (HTE)**, or steam electrolysis, has the potential for higher efficiency than conventional electrolysis. High-temperature electrolysis uses a combination of thermal energy and electricity to split water in a device very similar to a solid oxide fuel cell (SOFC). Thermal energy is used to produce high-temperature steam, which results in a reduction of the electrical energy required for electrolysis. HTE has the potential for higher efficiency than conventional electrolysis due to both lower inherent cell losses and the direct use of thermal energy for part of the dissociation energy. High temperature electrolyzers use similar materials and technology to those used in solid-oxide fuel cells. Electrolyzer cells are limited in size so that large-scale applications would be composed of many smaller electrolyzer modules.

- **Thermochemical cycles** produce hydrogen through a coupled set of chemical reactions where the net result is the production of hydrogen and oxygen from water at much lower temperatures than direct thermal decomposition. Energy is supplied as heat in the temperature range necessary to drive the endothermic reactions, generally 750 to 1000/C or higher. All process chemicals in the system are fully recycled. Because the net effect of the cycle is water dissociation and separation of hydrogen and oxygen, the theoretical minimum energy for any of these cycles is the heat of formation of liquid water at 25/C and 1 atmosphere. In practice, additional energy is consumed by stream processing which entails, (1) heating and pressurizing reactants and products, (2) separating reaction products, (3) transferring heat with heat exchangers, and (4) rejecting low-temperature heat. The energy to drive the reactions is predominantly, if not exclusively, heat. If heat is the only energy used for the reactions, then the process is called a thermochemical cycle.

- **Hybrid cycles** involve both thermochemical steps and electrolytic steps. Hybrid cycles have potential to accomplish reactions at lower temperatures, but also introduce the complexity of electricity generation and conversion inefficiency. The most common hybrid cycles replace one or more of the high temperature reactions in a thermochemical cycle with an electrolytic step that often simplifies the chemical separations processing and reduces the number of constituents, but with the potential for somewhat reduced efficiency and more linear scaling than purely thermochemical processes.

3B-2.3. Nuclear Hydrogen Production Considerations

The choice of whether to consider H_2 production as a potential product for a new nuclear plant obviously depends on market demand and the cost of hydrogen. Although the rate of increase of hydrogen demand is uncertain – depending on the technical, environmental and political factors, it is clear that demand will increase and that current production methods depending on natural gas are finite. The introduction of new applications (such as fuel cell power peaking) could change the picture, but the demand for refined fuels and expanding chemical industry use indicates increases in the range of 5 to 7 % per year. The tradeoffs between these processes are complex – application and timing dependent. For most of the advanced hydrogen production options, including HTE and thermochemical cycles, research is at an early stage and it will take some time before reliable cost estimates are available. However, several general aspects of these potential nuclear hydrogen production methods are apparent even at this early stage.

- **Scaling** – All of these production methods can be scaled to large sizes, but it is generally assumed that the purely thermochemical cycles should scale more efficiently. Electrolytic processes will require a modular approach and the economies of scale will be derived from the mass production of smaller units. Thermochemical cycles, like other chemical process plants, are assumed to scale with area or volume – so that large scales could be more cost effective. There are obviously many other factors, and the cost effectiveness of the scaling of these technologies is an important research area in the current DOE program.

- **Timing** – Thermochemical cycle research has been dormant for the last 20 years, and current efforts are now underway in several countries. Current work is focused on lab scale experiments to confirm feasibility and efficiency analysis. Pilot scale demonstrations of any cycle at an engineering level are 5 to 10 years away. (DOE plans pilot scale experiments in the 2010 time frame if funding is available). Depending on the results of these tests, commercial demonstrations are planned for the 2017 to 2020 time frame. HTE technology may be available sooner than TC cycles, but the costs of the high temperature electrolyzers must be reduced significantly to enable commercial development. For the next 7 to 10 years, conventional electrolysis may be the only large-scale commercially demonstrated technology. This would be particularly true for a multi-product nuclear plant (electricity, hydrogen, etc), where the flexibility to produce electricity as a primary product, and hydrogen during off peak hours may be important in the initial phase.

- **Nuclear Plant Applications/Characteristics** – Nuclear plants impose additional constraints and requirements on the siting and potential applications that can be considered. In general the nuclear plant will dominate the siting issues for a new facility, and the nuclear plant characteristics are more consistent with large centralized applications than small and distributed. The potentially more efficient and advanced methods (thermochemical and HTE) essentially require collocation due to the close coupling needed for the transport of high temperature for process heat. This is consistent with requirements for many large-scale near term applications (refining, power peaking) particularly for a dedicated plant (single purpose hydrogen), but would require new distribution system for distributed applications. Conventional electrolysis does not require collocation or large-scale initial applications, and therefore may offer near term flexibility for initial applications.

3B-3. HYDROGEN COST CONSIDERATIONS

3B-3.1. Hydrogen from Natural Gas

The cost of hydrogen is the obvious metric in assessing the viability of nuclear hydrogen. Current steam methane reforming methods produce hydrogen at a cost of about 1.0 \$/kg - assuming a natural gas price of about 3\$/MBtu. A kilogram of hydrogen is the energy equivalent to about one gallon of gasoline. The price of hydrogen produced from natural gas is obviously very sensitive to the cost of the natural gas feedstock. An approximate rule of thumb is:

$$C_{HSMR} = 0.15\frac{\$}{kg} + 0.29\frac{MBtu}{kg}C_{NG}$$

where C_{HSMR} is the cost of hydrogen per kg when produced by SMR and C_{NG} is the cost of natural gas (in \$/MBtu) . The cost of hydrogen as a function of natural gas cost based on this algorithm is shown in the table and figure below.

Table 3B-2. Cost of H_2 Production from Steam-Reforming of Natural Gas.

Natural Gas Cost ($/MBtu)	Hydrogen Cost ($/kg)
2	0.73
4	1.31
6	1.89
8	2.47
10	3.05

When comparing these costs with current gasoline costs, several factors must be kept in mind:

- Retail gasoline costs include significant distribution costs and taxes that are not accounted for in the cost of hydrogen above.
- Most sources assume that the eventual end uses of hydrogen will involve significantly higher efficiency technologies. Estimates of efficiencies for fuel cell cars are up to 50+ % - compared to about 15-20 % for the current generation of internal combustion vehicles. If these goals are achieved, the effective cost of hydrogen could be reduced by a factor of 2 to 3. These reductions are of course not relevant to refining or power peaking applications.

- Any form of carbon or sequestration regulation (taxes, incentives, etc) could also change the cost comparison. Nuclear or renewable hydrogen production may have additional cost benefits in that case.

Direct comparisons are difficult until all assumptions are accounted for, but the table above provides a range of current hydrogen costs that provide a point of reference for future nuclear hydrogen costs.

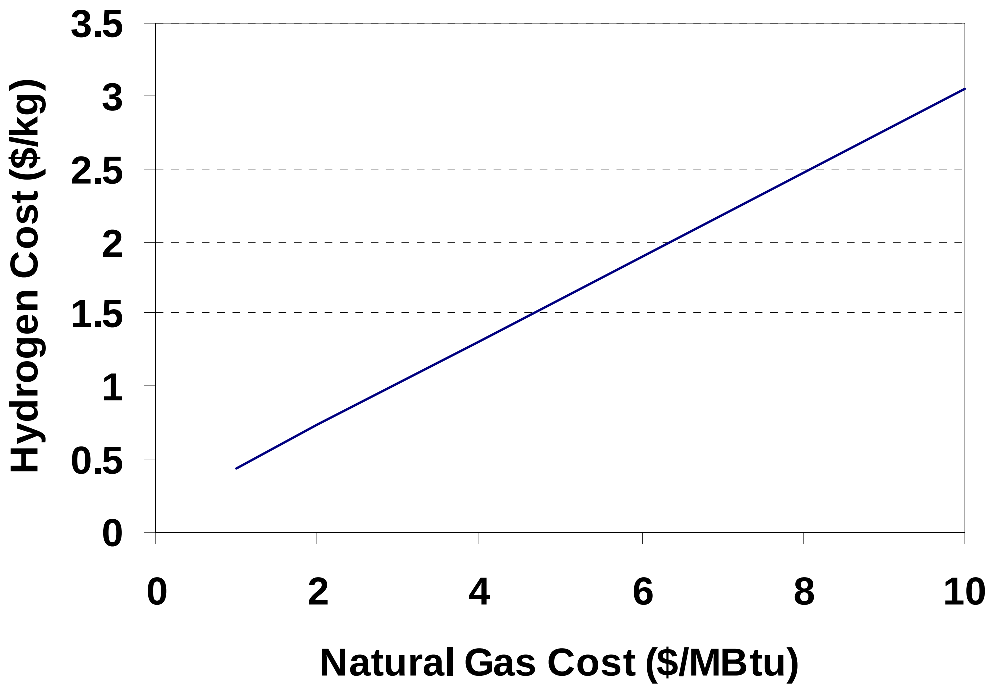

Figure 3B-2. Cost of Hydrogen Steam-Methane Reforming vs Cost of the Natural Gas Feedstock

3B3.2. Hydrogen from Water Electrolysis

For comparison, electrolysis of water using grid electricity is estimated to produce hydrogen at about 2.25 to 3.00 $/kg, depending on financial and operational assumptions. These hydrogen costs are dominated by the price of electricity. The components of the costs are shown in the table below — using representative values for capital and operating expenses.

Table 3B-3. Estimated Cost of H_2 Production from Electrolysis

Cost Component	Value	Hydrogen Cost Component
Energy Cost (52 kWh/kg of H_2 at 75% plant effic.)	0.04 $/kWh	2.08 $/kg
Capital Cost Recovery	(480 $/kW) (10% int/y)(52 kWh/kg)/(8760 h/y) = 0.28/kg	0.28 $/kg
Operating Cost	(7% of capital cost)	0.20 $/kg
Total Cost		2.56 $/kg

Although different financial or operating assumptions will result in considerably different numbers, the table above illustrates that the cost of electricity will dominate the cost of hydrogen production by electrolysis unless electricity is available at considerably reduced or off peak rates. It also illustrates that electrolysis and steam methane reforming are similar costs if natural gas increases to around 8 to 10 $/MBtu. Indeed, the case may be even stronger. Electricity in non-peak hours can be purchased at 0.02 $/kWh. This would make electrolysis competitive with SMR at about 4.75$/ MBtu, which is close to today's prices (assuming all the assumptions in the simple model described above are valid).

Simple formulae can be derived for the cost of hydrogen from electrolysis:

$$C_{Hel} = \frac{C_{cap}\left(r_{\text{int}} + r_{O\&M}\right)E_{H2}}{\eta N_h} + C_{el}\frac{E_{H2}}{\eta} \qquad E_{H2} = 39\frac{kWh}{kg}$$

$$\eta = 0.75$$

$$C_{NG} = 5\frac{\$}{MBtu}$$

$$N_h = 8760\frac{hr}{yr}$$

$$C_{cap} = 480\ \frac{\$}{kWh}$$

$$C_{Hel} = 4\frac{cents}{kWh}$$

$$r_{\text{int}} = 0.10\ per\ .year$$

$$r_{O\&M} = 0.07\ per\ .year$$

To find where electrolysis becomes competitive with SMR, we equate the electrolysis cost to the SMR cost and derive a relationship between the cost of natural gas and the cost of electricity (holding everything else constant at the values shown above):

$$C_{HSMR} = 0.15\frac{\$}{kg} + 0.29\frac{MBtu}{kg}C_{NG} \qquad C_{HSMR} = C_{Hel}$$

$$C_{Hel} = 0.48\frac{\$}{kg} + 52\frac{kWh}{kg}C_{el} \qquad C_{NG} = 1.14\frac{\$}{MBtu} + 179\frac{kWh}{MBtu}C_{el}$$

Figure 3B-3 shows a plot of the condition where the cost of hydrogen production from electrolysis equals the SMR cost. Electrolysis is less expensive than SMR above the line, and more expensive below the line. *The cost of hydrogen per kg is given as label for particular points. For example, if electricity costs 0.02 $/kW, then electrolysis is less expensive than SMR if the cost of natural gas is greater than 4.50 $/MBtu. The cost of hydrogen under these conditions is 1.53 $/kg.*

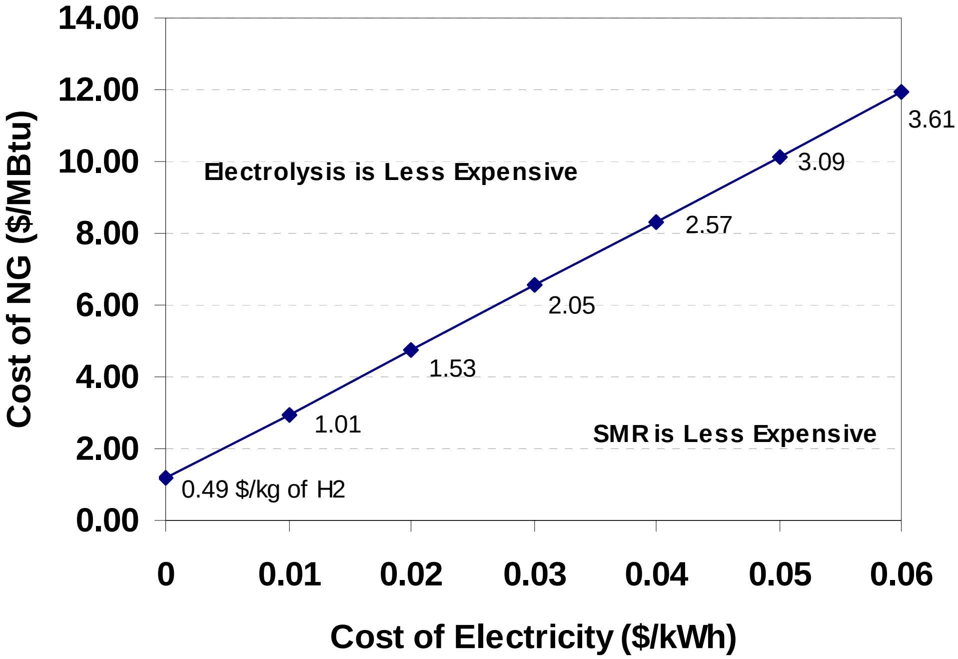

Figure 3B-3. Cost of Natural Gas vs Cost of Electricity where Electrolysis Becomes Competitive with Steam-Methane Reforming

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 Figure 3B-2, 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.

These approximate cost estimates provide are in rough agreement with more detailed studies performed by the National Renewable Energy Laboratory (NREL), as reported at the National Hydrogen Association Hydrogen Conference (April 26-29, 2004, Los Angeles, CA). Figure B3-4 shows a chart from a presentation by D. Mears, et al. The chart shows the current and projected H_2 production costs for various production techniques. Wind and nuclear assume electrolysis. Figure 3B-5 shows a breakout of the various components in those costs. For nuclear, the electrical costs are included in the category called “capital”. Wind and nuclear, using electrolysis, can compete with natural gas (i.e. steam methane reforming), coal, and biomass if the cost of natural gas increases or the cost of electricity is low (e.g. by night-time use only).

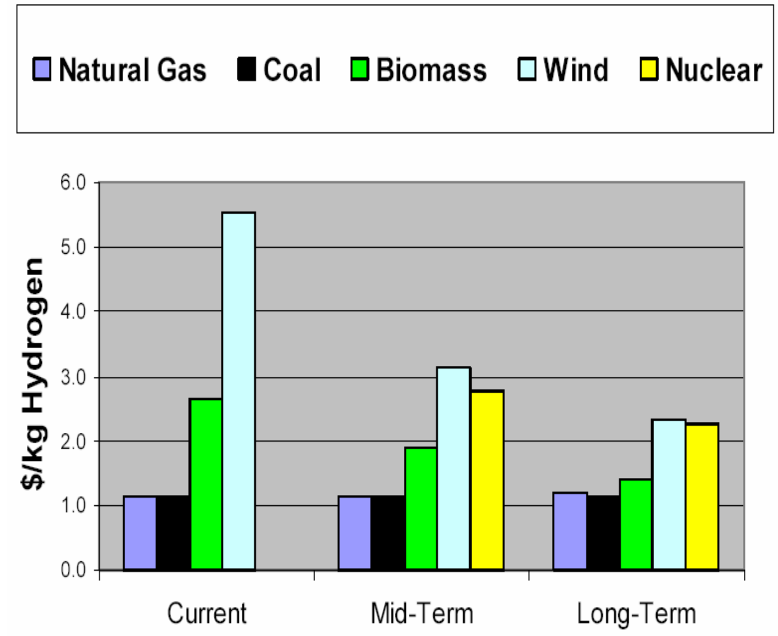

Figure 3B-4. Comparison of Current and Projected Hydrogen Production Costs (D. Mears, et al.)

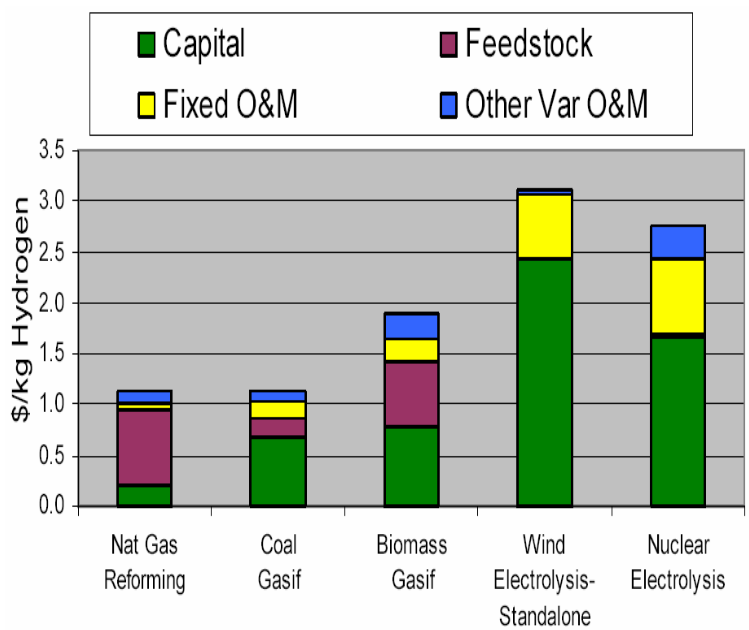

Figure 3B-5. Breakout of Component Costa for Hydrogen Production in the Midterm (D. Mears, et al.)

3B-3.3 Projected Costs for HTE and Thermochemical Hydrogen

High temperature electrolysis (HTE) is more efficient in both cell losses and in the direct use of use thermal energy for dissociation, avoiding the losses inherent in electrical conversion for that component of the energy requirement. HTE also requires much higher outlet temperatures (500 to 900 C) and collocation of the nuclear and hydrogen facilities. This reduces the energy cost, and focuses attention on the capital cost of the high temperature electrolyzer. Current costs for the SOFC based electrolyzers are very high (~1000’s $/kWe) but the assumption is that mass production will significantly reduce cell capital costs. If we assume a future capital cost of 400 $/kW/y, and similar recovery rate and operating expense assumptions to the table above, the future hydrogen cost produced from a mature HTE plant would be in the range of 2.0 to 2.25 $/kg.

Thermochemical cycles are subject to large cost uncertainties since no process is mature enough to be reliable projected to a commercial scale. The primary uncertainties are efficiency and capital cost. Although the energy required is thermal (no electrical conversion losses), there are significant uncertainties in efficiency and in the final plant configuration and capital cost. Assuming 45 % efficiency and a mature industry capital cost of the thermochemical plant of 500 $/kWth, the thermochemical plant would produce hydrogen in the range of 1.80 to 2.20 $/kg. Thermal energy costs are lower than electrical, but outlet temperatures are required to be in the range of 800 to 900 C for thermochemical cycle operation. This requires new high temperature reactor development, and collocation of chemical and nuclear plants.

Although these numbers are intended to be representative, and are strongly dependent on assumptions, they provide some perspective on the comparison of current hydrogen and future nuclear hydrogen cost comparisons.

3B-4. NEAR TERM NUCLEAR HYDROGEN CONSIDERATIONS

The potential near term applications for nuclear hydrogen include a range of smaller chemical process applications as well as the large refining or power peaking applications referred to above. We focused on the larger applications which might provide some motivation for the near term construction of a nuclear plant which could include hydrogen production as a major product. Several of the factors and influences discussed above suggest that in the near term, conventional electrolysis may be the production option to consider when evaluating a business case.

Thermochemical cycles are early in the research phase and reliable projections and commercialization decisions are a decade or more away. Of the thermochemical cycles the hybrid sulfur approach is the most mature technically but will have cost and scaling considerations that need to be evaluated before commercialization. DOE is considering pilot plants for thermochemical demonstration in the 2010 to 2015 time frame and commercial scale demonstrations in the 2017 to 2020 time frame.

High temperature electrolysis is currently available in small scale units, but costs are a major factor. Current research focuses on optimization and manufacturing techniques to reduce costs. HTE engineering will take time to mature. The cost of electricity is still an important factor in the viability of the HTE approach.

Conventional electrolysis is the most likely near term technology for emissions free nuclear hydrogen production. The cost of electricity (nuclear plant capital cost dominated) remains as the key to economic hydrogen production. Off peak strategies may provide paths to early viability.

3B-5. CONVENTIONAL ELECTROLYSIS

3B-5.1. Electrolysis Description

In conventional electrolysis, electricity is used directly with water by producing an electrostatic potential that dissociates the water into hydrogen and oxygen gas. The fundamental process is:

$$4\ H_2O \rightarrow 4\ H_2 + 2\ O_2$$

The process requires a minimum of 1.23 V, and the theoretical energy required (i.e., 100% efficiency) is 39 kWh per kg of H_2 produced. (Note This is the “High Heat Value”, or HHV, and is based on starting with room-temperature liquid water and ending with room-temperature hydrogen.).

Commercial electrolyzers have three techniques for achieving this overall operation. The first two techniques use an aqueous solution of potassium hydroxide (KOH) between the electrodes and are referred to as “alkaline electrolyzers”. (See Figure 3B-6). In the unipolar version, the electrolyzer cells are connected in parallel. In the bipolar version, the cells are connected in series. The bipolar approach increases the system voltage, which reduces the electrical losses. In both cases there is a membrane between the electrodes to separate the hydrogen gas from the oxygen gas as it is produced. The water is split at the cathode (which is the negatively charged electrode) to produce H_2 gas:

$$4\ H_2O + 4e^- \rightarrow 2\ H_2 + 4\ OH$$

The KOH transports the OH- ions through the membrane to the anode electrode where the following reaction takes place and produces O2 gas:

$$4\ OH \rightarrow O_2 + 2\ H_2O + 4e^-$$

The electrode wires transport the electrons back to the cathode to complete the cycle, while the power supply boosts the voltage of these electrons above 1.23 V to supply energy to the process.

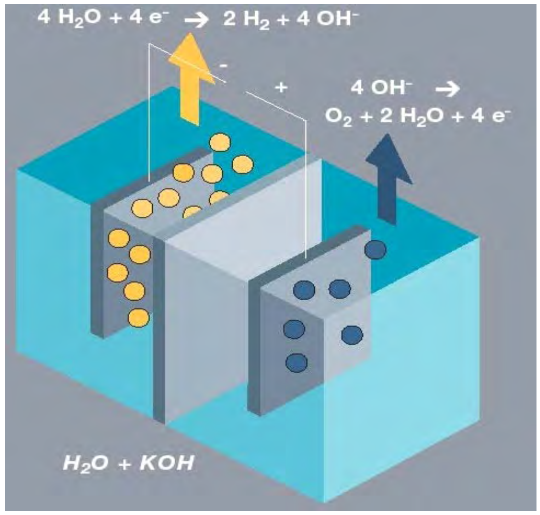

Figure 3B-6. Alkaline Electrolyzer. The KOH Solution Transports OH - Ions from the Cathode to the Anode. A Membrane Separates the H_2 from the O_2 *(Adapted from Linde)*

The third technique uses a Proton Exchange Membrane (PEM) instead of the aqueous solution of KOH, and is referred to as a "PEM electrolyzer". (See Figure 5-2). The water is split at the anode in this case and produces O_2 gas

$$2\ H_2O \rightarrow O_2 + 4\ H^+ + 4\ e^-$$

The H+ ions (i.e., protons) are transmitted through the PEM to the cathode where the following reaction takes place, producing H_2 gas

$$4\ H^+ + 4\ e^- \rightarrow 2\ H_2$$

PEM electrolysis is a more recent innovation than alkaline electrolysis; few companies provide this option at this time.

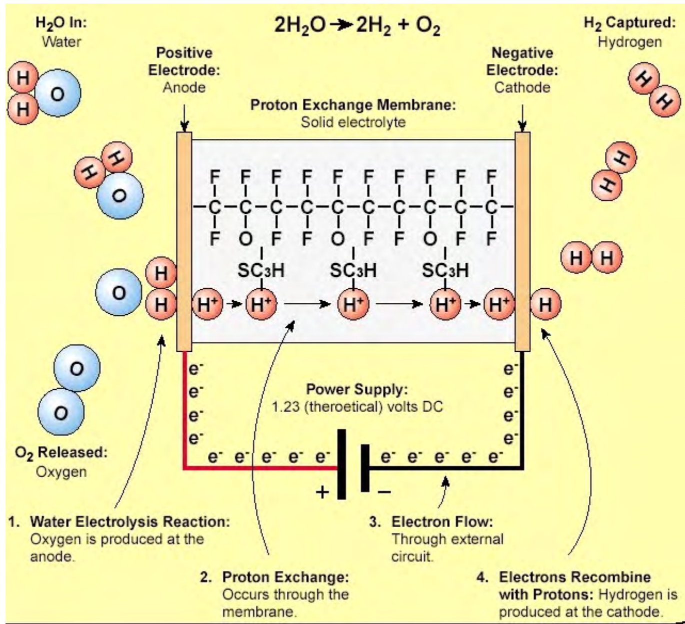

Figure 3B-7. Proton Exchange Membrane (PEM) Electrolyzer. The PEM Transports H^+ Ions from the Anode to the Cathode. The Membrane also Separates the H_2 from the O_2. Adapted from HomePowers.)

In addition to the electrolyzer unit itself, a system requires additional components. Figure 3B-8 shows a schematic of the typical system. The input water needs to be fairly pure so the water is passed through a processing unit before being stored in readiness for the electrolyzer unit. Power conditioning is needed to convert line AC to DC at the proper voltage. The H_2 gas will need to be separated out from KOH and water droplets, dried, and compressed for storage if it is not used immediately at the exit pressure of the electrolyzer (which is usually about 400 psi).

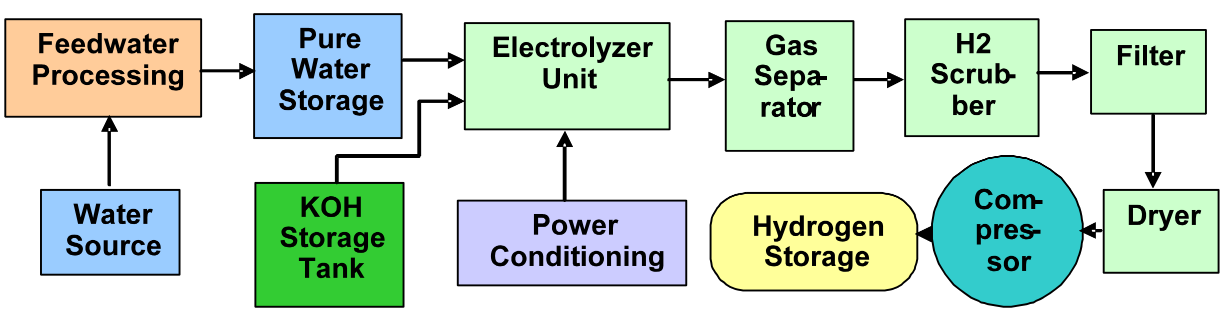

Figure 3B-8 Electrolyzer System

Figure 3B-9 shows an example set of hardware from Stuart Energy Systems Corporation. Many of these components have electrical power consumption which impacts the overall efficiency of H_2 production. There are also potential maintenance costs and lifetime limitations.

The overall electrical efficiency (or “wallplug efficiency”) of this process is important since electricity costs dominate the overall cost for a large system. All of the required power to produce the hydrogen needs to be included in the assessment of the efficiency. This number is then divided by the theoretical energy of dissociation from water into room-temperature H_2 and O_2 gas (39 kWh/kg of H_2). As will be seen, commercial units can produce up to 78% wallplug efficiency. (Claims of higher numbers usually do not include all the system losses and often refer only to the cell efficiency). The energy needed to compress the gas to the final desired pressure also needs to be included. This can amount to another few percent loss in efficiency.

Another system efficiency measures the fraction of the water that is converted into H_2 and O_2. This is not an important number because feedwater is fairly inexpensive, even after being purified. But the mass efficiency is nonetheless fairly high: around 80%.

3B-5.2. Survey of Companies and Capabilities

There are numerous companies that offer commercial products that make hydrogen gas by electrolysis. Table 3B-4 below lists the major companies along with descriptions of the process they use and the peak production rate of their largest unit. Web page addresses are also included (although those are subject to change at any time). The listed “wallplug efficiency” includes all the electrical power needed to run the system and will be discussed in a later section. The largest available unit provides 43.6 kg/hr at 73% wallplug efficiency.

Figure 3B-9. Components from Stuart Energy Systems Electrolyzer

Table 3B-4 summarizes the production capabilities of the various electrolyzer units from each of these companies. The table shows production rates as well as system efficiency. The energy required to separate water into hydrogen and oxygen is 39 kWh/kg of hydrogen produced. The electrical efficiency of the electrolyzer cell alone is as high as 83% in some of these commercial units. But this is not the complete story. The other energy losses such as those in power conditioning and that needed to operate the system need to be considered. The net efficiency of production thus should be defined as the energy produced when 1 kg is combined with oxygen divided by the total energy needed to produce 1 kg of hydrogen at a usable pressure and temperature. With these other losses included, the total efficiency (or "wallplug efficiency") is lower. Nonetheless, the wallplug efficiency of many of these commercial units is 73%. This is fairly good and does not leave much room for improvement.

Table 3B-4. Production Capabilities of Various Hydrogen-Production Units

Company	Product	Electrolyzer Type	H_2 Production (kg/h)	System Power Required (kW)	Wallplug Efficy. (%)
			Max		
Avalance	Hydrofiller 15	alk., unipolar	0.04	2	70
Avalance	Hydrofiller 50	alk., unipolar	0.1	7.05	75
Avalance	Hydrofiller 175	alk., unipolar	0.4	25	70
Norsk Hydro EL	HPE 10	alk., bipolar	0.9	48	73
Norsk Hydro EL	HPE 12	alk., bipolar	1.1	27.6	73
Norsk Hydro EL	HPE 16	alk., bipolar	1.4	76.8	73
Norsk Hydro EL	HPE 20	alk., bipolar	1.8	96	73
Norsk Hydro EL	HPE 24	alk., bipolar	2.2	115.2	73
Norsk Hydro EL	HPE 30	alk., bipolar	2.7	144	73
Norsk Hydro EL	HPE 40	alk., bipolar	3.6	192	73
Norsk Hydro EL	HPE 50	alk., bipolar	4.5	240	73
Norsk Hydro EL	HPE 60	alk., bipolar	5.4	288	73
Norsk Hydro EL	Atmospheric 5010 (4000 Amp)	alk., bipolar	4.5	240	73
Norsk Hydro EL	Atmospheric 5010 (5150 Amp)	alk., bipolar	4.5	240	73

Table 3B-4. Production Capabilities of Various Hydrogen-Production Units

Norsk Hydro EL	Atmospheric 5020 (4000 Amp)	alk., bipolar	13.5	720	73
Norsk Hydro EL	Atmospheric 5020 (5150 Amp)	alk., bipolar	13.5	720	73
Norsk Hydro EL	Atmospheric 5030 (4000 Amp)	alk., bipolar	27	1440	73
Norsk Hydro EL	Atmospheric 5020 (5150 Amp)	alk., bipolar	27	1440	73
Norsk Hydro EL	Atmospheric 5040 (4000 Amp)	alk., bipolar	33.9	1809.6	73
Norsk Hydro EL	Atmospheric 5040 (5150 Amp)	alk., bipolar	43.6	2328	73
Proton Energy	HOGEN 20	PEM	0.004	2.8	63
Proton Energy	HOGEN 40	PEM	0.1	5.6	63
Proton Energy	HOGEN H Series	PEM	0.5	37.8	56
Stuart Energy	IMET 300 (1 stack)	alk., bipolar	0.3	14.7	72
Stuart Energy	IMET 1000 (1 stack)	alk., bipolar	0.4	72	73
Stuart Energy	IMET 1000 (2 stack)	alk., bipolar	2.7	144	73
Stuart Energy	IMET 1000 (3 stack)	alk., bipolar	4	216	73
Stuart Energy	IMET 1000 (4 stack)	alk., bipolar	5.4	288	73
Teledyne Energy	HM 50	alk., bipolar	0.3	17.08	57
Teledyne Energy	HM 100	alk., bipolar	0.5	31.92	62
Teledyne Energy	HM125	alk., bipolar	0.6	39.9	62
Teledyne Energy	HM 150	alk., bipolar	0.8	47.88	62
Teledyne Energy	HM 200	alk., bipolar	1	59.36	66
Teledyne Energy	EC 500	alk., bipolar	2.5	156.8	63
Teledyne Energy	EC600	alk., bipolar	3	188.16	63
Teledyne Energy	EC750	alk., bipolar	3.8	235.2	63

Table 3B-4. Production Capabilities of Various Hydrogen-Production Units

Teledyne Energy	HP1350	alk., bipolar	6.75	420	63
Teledyne Energy	HP1800	alk., bipolar	9	560	63
Teledyne Energy	HP 2250	alk., bipolar	11.25	700	63
Teledyne Energy	HP 2700	alk., bipolar	13.5	840	63
Giner Electrochemical	high pressure	PEM	1.2		
	aerospace	PEM	3.6		
Air Products	PRISM EL Series	alk	10.8	840	
Hamilton Sundstrand SSI	ES series 12280	PEM	5.5		

It is of interest to determine whether the system efficiency increases or decreases with production unit size. Figure 3B-10 shows a plot of production rate vs. system efficiency. There does not appear to be any trend. This is perhaps encouraging, for it is conceivable that high efficiency would be limited to carefully-controlled laboratory-scale systems. But the modular nature of the production units apparently allows good efficiency to be achieved even at larger production rates. However, there is still a long way to go to the production rates needed for a hydrogen economy and for utilizing a significant fraction of a nuclear power plant.

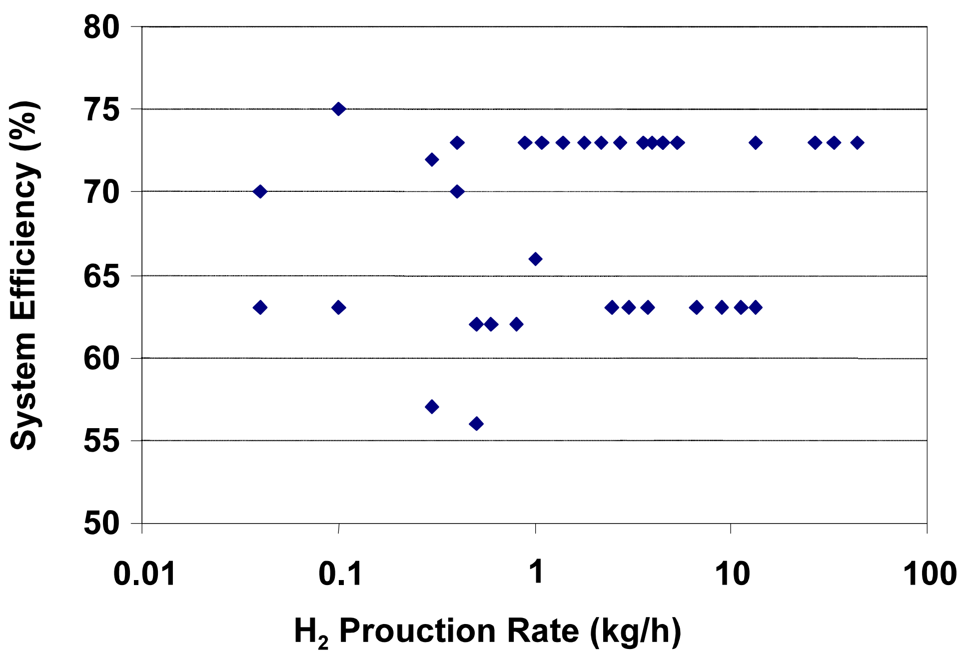

Figure 3B-10. Production Rate vs. System Efficiency for Commercial Units (Table 3B-4)

3B-5.3. Costs for Electrolysis-Produced Hydrogen

A small city with 100,000 cars used for 12,000 mi/yr would require at least 54000 kg/day of hydrogen (at 60 mi/kg using fuel cells). This in turn would require 2250 kg/hr and 120 MW of electricity at 73% system efficiency if production were 24 hours per day. The largest unit available today is 43.6 kg/h (from Norsk Hydro). So if 10 units were needed to produce the 2250 kg/h, each unit would need to be 225 kg/hr, which is about 5 times the size of the Norsk Hydro unit. While this is a large scale-up, the modular nature of electrolysis would make such an extrapolation reasonable.

The cost of H_2 includes energy costs, capital costs, and operating and maintenance costs, taxes, return on investment, and inflation rate. Several DOE studies project costs for electrolyzer installations to be in the 500 to 1000 $/kWe range for large-scale installations in the future. A 2000 kg/hr unit would require 107 MW of electricity at 73% system efficiency. At that capital cost, the electrolyzer system then would cost about $80 million. At 10% interest per year, the capital costs would contribute about $0.44/kg to the cost of hydrogen produced.. This assumes 24-hr per day operation. Operating and other costs need to be added to this, but this very preliminary estimate supports the previous conclusion that at large sizes the cost of electricity dominates the cost of H_2 production.

3B-6. THERMOCHEMICAL CYCLES

Thermochemical cycles produce hydrogen through a series of chemical reactions where the net result is the production of hydrogen and oxygen from water at much lower temperatures than direct thermal decomposition. Energy is supplied as heat in the temperature range necessary to drive the endothermic reactions, generally 750 to 1000/C or higher. All process chemicals in the system are fully recycled. Thermochemical cycles were widely investigated from the late 1960's through the mid-1980s. The advantages of thermochemical cycles are generally considered to be high projected efficiencies, on the order of 50% or more, and attractive scaling characteristics for large-scale applications. However, of the more than 200 cycles that have been identified in the literature, many have been found to be unworkable, have low efficiency, or require excessive temperatures. Thermochemical cycle technology is at a relatively early stage, and only a few cycles have been demonstrated at the laboratory-scale. Although there is greater uncertainty in the outcome of R&D, there is also potential for significant process improvement based on more recent advances in materials and chemical technology over the past two decades.

3B-6.1. Summary of Previous Thermochemical Cycle Research

The first major program was at the European Community Joint Research Center (ISPRA), beginning in the late 1960s and continuing through 1983. The goal of this work was to identify thermochemical cycles to couple to the high-temperature, gas-cooled reactor. The three-phase program investigated 24 cycles based on the chemistries of mercury, manganese, vanadium and iron. In the United States, the Gas Research Institute (now known as the Gas Technology Institute) funded a long-term program that systematically examined 200 distinct thermochemical cycles. The three that were most highly ranked were hybrid sulfur, sulfur iodine, and hybrid copper sulfate.

The largest single-process development effort was conducted by Westinghouse Corporation to develop the hybrid sulfur process. This effort progressed through a laboratory demonstration with the final product being a conceptual design report for a pilot plant.

More recently (1999), a literature evaluation of thermochemical processes done under the Nuclear Energy Research Initiative (NERI) study reviewed available information for 115 cycles, which were ranked by complexity (reactions, separations, elements, and corrosiveness), development maturity (demonstration level and publications), and performance (efficiency and cost). The four leading processes were hybrid sulfur, sulfur-bromide hybrid, UT-3 (calcium bromine), and sulfur iodine. The new process was the UT-3 process developed by the University of Tokyo since the 1970s. The work on this new cycle was initiated to provide a lower-temperature process that would be compatible with lower-temperature heat sources. The sulfur-based cycles were commonly identified in all studies: sulfur-iodine, hybrid sulfur, and sulfur-bromine hybrid. Theses cycles were demonstrated to have high efficiencies and were among the least complex. They have also been extensively demonstrated at a laboratory-scale to confirm performance characteristics.

Currently the DOE Nuclear Hydrogen Initiative (NHI) is performing research on thermochemical cycles for application to advanced (Generation IV) reactors. This program is performing research on sulfur-based cycle (sulfur-iodine and hybrid sulfur, and calcium- bromine). Lab scale demonstrations of these and potentially other cycles are planned for the 2007 time frame.

3B-6.2. Sulfur-Based Cycles

The decomposition of sulfuric acid is common to all sulfur-based cycles. The sulfur-iodine and sulfur-bromine hybrid cycles involve primary reactions that produce hydrogen-iodine (HI) or hydrogen-bromine (HBr) in solution, which must be separated and decomposed to produce hydrogen. Hydrogen is produced in the sulfur-iodine cycle by thermal decomposition of hydrogen-iodine, while the hybrid sulfur and sulfur-bromine hybrid cycles produce hydrogen in an electrolytic step.

Sulfur Iodine – This all-fluids-and-gases cycle involves three primary thermochemical steps which are,

- H_2SO_4 (l) W H_2O (g) + SO_2 (g) + ½ O_2 (g) [1223 K],
- 2HI (g) W I2 (l) + H_2 (g) [723 K],
- $2H_2O$ (l) + SO_2 (g) + I_2 (l) W H_2SO_4 (l) + 2HI (l) [393 K].

Unique technical issues associated with this specific cycle include efficient separation of hydrogen iodide, minimizing the recycle rates of chemicals within the process per unit of hydrogen produced, and reducing the inventories of iodine within the process, which, although not consumed, is expensive and toxic. Multiple alternative technical solutions (primarily using membranes) have been proposed to address these challenges. The distillation of hydrogen-iodine from solution is the most difficult process issue for this cycle.

Hybrid-Sulfur - This all-fluids-and-gases cycle involves two primary thermochemical steps which are,

- H_2SO4 (l) $\rightarrow$ H_2O (g) + SO_2 (g) + ½ O_2 (g) [1223 K]
- $2H_2O$ (l) + SO_2 (g) + electricity $\rightarrow$ H_2SO_4 (l) + H_2 (g) [353 K].

This cycle consists of only two reactions, the first of which is identical to the sulfuric acid decomposition reaction for the Sulfur-Iodine cycle. The second reaction is an electrochemical reaction requiring electricity, and produces hydrogen and sulfuric acid.

3B-6.3. Calcium Bromide Cycles

The calcium-bromine cycle has been demonstrated at 1 l/h for ~100 h. The primary incentive to develop this cycle is that the peak temperature is lower than for the sulfur cycles, typically 750°C. Efficiencies have been estimated between 40 to 50%. The key R&D areas that must be addressed for this cycle are associated with the solid-gas reactions that characterize the cycle. The CaO, $CaBr_2$, and Fe_3O_4, and $FeBr_2$ reactants in fixed beds or other configurations undergo volume changes in each reaction of the cycle. Research efforts to date have not been able to demonstrate the integrity of these reaction beds after many cycles.

The calcium-bromine UT-3 cycle reactions occur in pairs of solid reaction beds. One pair contains calcium-bromide and calcium-oxide and the other pair contains iron-oxide and iron-bromide.

- $CaBr_2 + H_2O \rightarrow CaO + 2HBr$ (HBr generation) 957 K
- $3FeBr_2 + 4H_2O \rightarrow Fe_3O_4 + 6HBr + H_2$ (H_2 generation) 724 K
- $Fe_3O_4 + 8HBr \rightarrow 3FeBr_2 + 4H_2O + Br_2$ ($FeBr_2$ regen) 483 K
- $CaO + Br_2 \rightarrow CaBr_2 + ½\, O_2$ ($CaBr_2$ regeneration) 845 K

The initial reaction steps form hydrogen-bromine from a high-temperature steam reaction with the calcium-bromide bed and hydrogen from the iron-bromide bed. A second series of reactions regenerates the calcium and iron-bromide reactants. When the initial reaction beds are fully converted, the flows are switched in each pair of beds and the same reactions occur in the opposite flow direction. Although this cycle has been demonstrated with reasonable efficiency, solid-gas reaction beds integrity has been a difficult problem and alternative approaches are being developed ay Argonne National Laboratory.

3B-6.4. Other Thermochemical Cycles

In addition to sulfur and calcium-bromine families of thermochemical cycles, several other cycles have been identified as promising due either to projected lower temperature requirements, high-advertised efficiencies, or other positive cycle characteristics. Examples of these cycles are given below. Additional analysis of these cycles is needed to assess the potential of these cycles to provide a more cost effective process.

Iron Chlorine Cycle W pure thermochemical, (873 to 973 K)

$3FeCl_2(s) + 4H_2O(g)$ W $Fe_3O_4(s) + 6HCl(g) + H_2(g)$

$Fe_3O_4(s) + 3/2\ Cl_2(g) + 6HCl(g)$ W $3FeCl_3(s) + 3H_2O(g) + ½\ O_2(g)$

$3FeCl_3(g)$ W $3FeCl_2(s) + 3/2\ Cl_2(g)$

Vanadium-Chlorine Cycle W 1123 K, Efficiency estimate 42.5%

$Cl_2(g) + H_2O(g)$ W $2HCl(g) + ½\ O_2(g)$

$2HCl(g) + 2VCl_2$ W $2VCl_3(s) + H_2(g)$

$4VCl_3$ W $2VCl_4(g) + 2VCl_2(s)$

$2VCl_4$ (l) W $Cl_2(g) + 2VCl_3(s)$

Copper-Chlorine Cycle W (500 to 600/C)

$2Cu(s) + 2HCl(g)$ W $2CuCl$(s or l) + $H_2(g)$

*$4CuCl(s)$ W $2Cu(s) + 2CuCl_2$(s or aq)

$2CuCl_2$(s or l) + $H_2O(g)$ W $CuCl_2\ CuO(s) + 2HCl(g)$

$CuCl_2\ CuO(s)$ W $2CuCl(l) + ½\ O_2(g)$

Copper-Sulfur Cycle W (825/C), Efficiency estimate 69-73% HHV

$CuO(s) + SO_2(g) + H_2O(l)$ W $CuSO_4(s) + H_2(g)$

$CuSO_4$ W $CuO(s) + SO_3(g)$

$SO_3(g)$ W $SO_2(g) + ½\ O_2(g)$

This list of cycles is only representative and not meant to be complete. Other cycles may appear in the future or other overlooked cycles in the literature may become viable based on new technologies. Technical advances in catalysts, membranes, etc. may offer improved performance, thereby justifying a reevaluation.

3B-6.5. Advantages/Disadvantages of Thermochemical Cycles

The primary advantages of thermochemical cycles are the potential for achieving total efficiencies of 50% or more, and potentially cost effective scaling to large sizes. Compared to traditional thermomechanical cycles that produce work from heat, thermochemical cycles have only recently been explored. Thus, thermochemical cycle technology has not matured and considerable improvements are anticipated. Furthermore, when these systems are scaled-up, heat losses are reduced and the volumes that can be handled increases rapidly as the system dimension increases.

The most prominent disadvantage of thermochemical cycles are the high temperature and corrosive environments for materials of construction. The working fluids are not the relatively inert gases found in power cycles such as helium or steam. Instead, corrosive acids at very high concentrations and temperatures are typical. For these fluids only ceramics have been found to be corrosion resistant. Unfortunately, ceramics are not easily used to construct vessels that are 5 to 10 meters in size and under pressure. Work is proceeding on innovative designs, and new materials for thermochemical cycles, but this is still an active area of research.

3B-7. HIGH TEMPERATURE ELECTROLYSIS

Electrolysis is the most straightforward approach currently available to produce hydrogen directly from water. Conventional electrolyzers are available with electric to hydrogen conversion efficiencies of 70%. This gives an overall hydrogen production efficiency of 23 to 28% if electricity generation is 33 to 40% efficient. High-temperature electrolysis (HTE), or steam electrolysis, has the potential for higher efficiency. Thermal energy is used to produce high-temperature steam, which results in a reduction of the electrical energy required for electrolysis. HTE has the potential for higher efficiency than conventional electrolysis and can be accomplished using similar materials and technology to those used in solid-oxide fuel cells (SOFC). Large-scale applications would be composed of many smaller electrolyzer modules. High-temperature electrolysis uses a combination of thermal energy and electricity to split water in a device very similar to an SOFC.

Fundamentally, the electrolytic cell consists of a solid oxide electrolyte (usually yttria-stabilized zirconia) with conducting electrodes deposited on either side of the electrolyte. The figure below shows a schematic of a high temperature electrolysis cell of the type currently being developed at the INEEL as part of the DOE Nuclear Hydrogen Initiative.

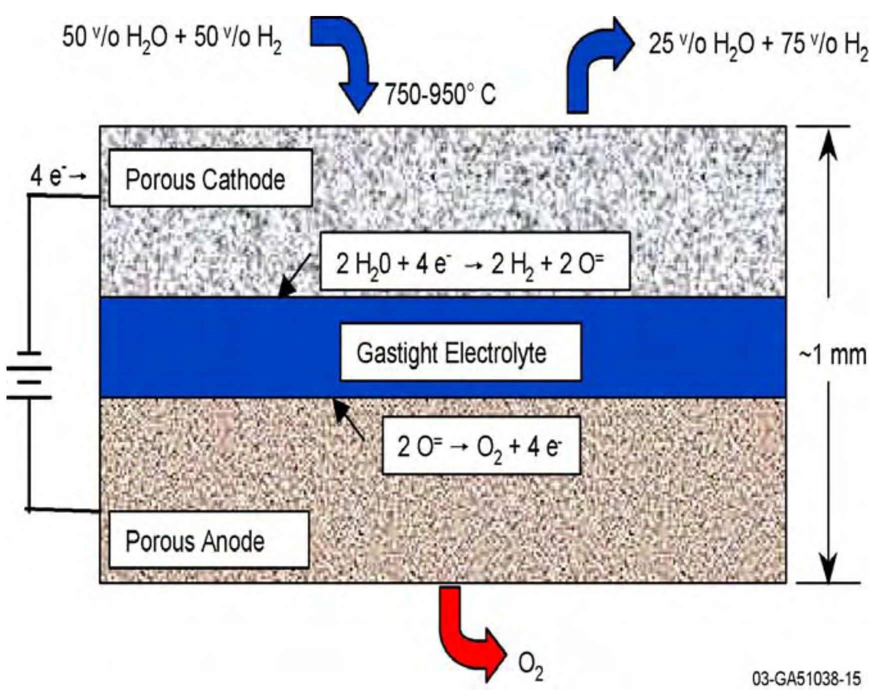

Figure 3B-11. Schematic of HTE Cell

A mixture of steam and hydrogen at 750-950/C is supplied to the anode side of the electrolyte. Oxygen ions are drawn through the electrolyte by the electrical potential and combine to oxygen on the cathode side. The steam-hydrogen mixture exits at about a 2575 volume ratio, and the water and hydrogen gas mixture is passed through a separator to separate hydrogen. While present experiments and fuel cells operate near atmospheric pressures, future cells may operate at pressures up to 5 MPa.

Because of shrinkage during sintering in current manufacturing processes, the size of individual cells is limited to about 15 cm^2. Therefore, a high-temperature electrolysis plant powered by a reactor would consist of an array of relatively small modules connected together with the necessary high-temperature gas manifolding, electrical, and control connections. Costs for SOFCs are currently high (~$5 to 10/kWe), primarily due to small-scale manufacture. Ongoing SOFC research is investigating approaches to reduce both materials and manufacturing costs. Current estimates are that large-scale manufacturing could potentially reduce costs by an order of magnitude.

3.8. Summary

There is a large potential future market for producing hydrogen as an alternative to gasoline for transportation. However, there is already a considerable market and production of hydrogen (over one million kg/h) for use in the petrochemical industry – if costs become competitive in the future. Steam-methane reforming of natural gas presently produces hydrogen at about 1.0 $/kg at natural gas costs of 3.00 $/MBtu. If natural gas costs increase to about 8 $/MBtu the hydrogen cost increases to about 2.50 $/kg.

If we are considering near term nuclear hydrogen capabilities, the most likely configuration is an advanced LWR producing electricity to power a large water electrolysis plant. The cost is dominated by the cost of electricity. Existing units can produce hydrogen with a total system efficiency (or "wallplug efficiency) of 73%. If electricity costs 0.04 – 0.05 $/kWh, then hydrogen produced by electrolysis has been estimated to cost in the range of 2.50 to 3.0 $/kg. But if off-peak nuclear-produced electricity is used at 0.02 $/kWh, then the estimated cost of hydrogen would be about 1.4 $/kg If carbon regulation or the use of off peak rates are envisioned, nuclear hydrogen may become viable sooner. It is also recognized that renewables – wind, solar, biomass may also present viable production options in the future. In the long run, a mix of technologies based on technical, environmental, and political influences may all have a role in future hydrogen production.

APPENDIX 3C. WATER DESALINATION USING OFF-PEAK OR COGENERATED POWER

3C-1. EXECUTIVE SUMMARY[22]

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. The purpose 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.

A 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 3C-1). 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.

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22 B.B. Cipiti and R.O. Gauntt, Sandia National Laboratories, Albuquerque, NM 87185

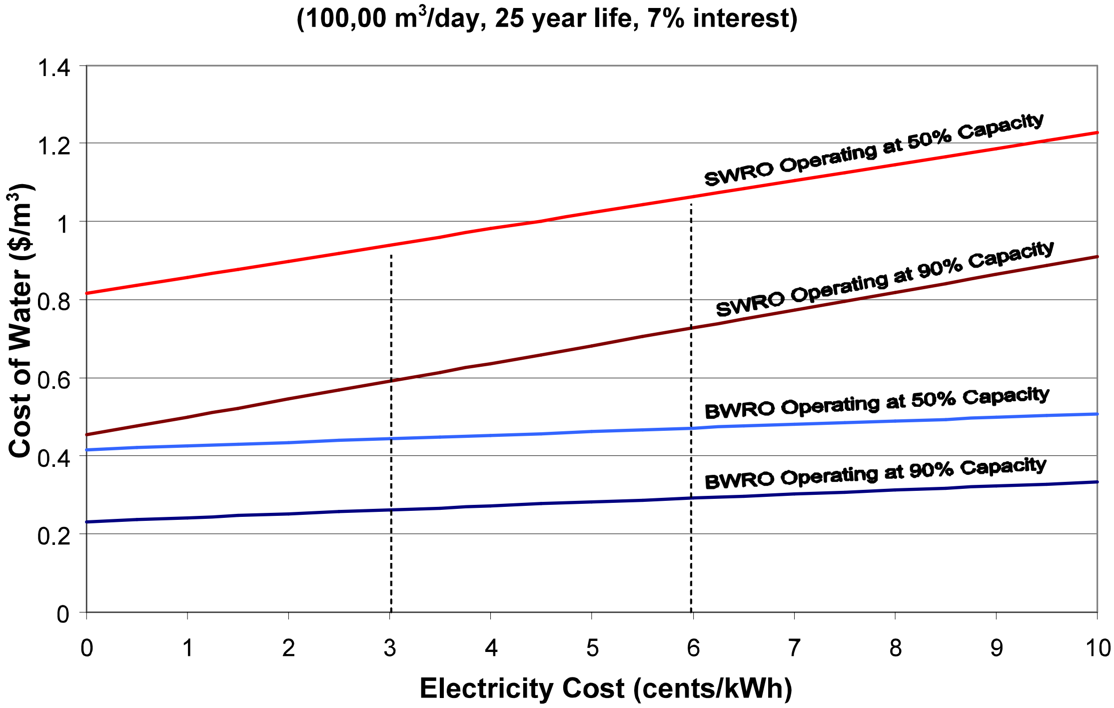

Figure 3C-1. BWRO & SWRO Plant Cost Water

Even if electricity at night is completely free, the cost of water will still be higher for a plant running at half capacity.

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 nuclear 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.

3C-2. INTRODUCTION

The continuing population growth both in our country and in the rest of the world will place ever-increasing demands on electricity and water supplies. Some may argue that water supplies are just as important as electricity supplies in sustaining economic growth.[23] Since saline water makes up the majority of the planet's water supply, it is likely that desalination technologies will be of central importance to meet demands in the coming century. Desalination requires significant amounts of energy, depending on the salinity of the water, so forging a link between power and water production is a logical step.

Advances in technology in past decades have decreased both the energy requirements for water desalination as well as the cost of water. In many areas such as the Middle East, desalination already makes up an important fraction of water supplies.[1] In the Unites States, water desalination is only beginning to take hold. At this point, water desalination must prove to be economically competitive. In coastal areas, or areas without good sources of fresh ground water, it is becoming more economic to desalinate water than to pipe it in over long distances.[1]

The purpose of this study is to evaluate the economics of water desalination in the state of Texas. In the future, Texas may need to rely on desalination to satisfy water demands. The state also will have increasing energy demands, and industries on the Gulf Coast are starting to be hurt by increasing natural gas prices. These industries need either cheaper power or process heat. The economics may be favorable at this time to build large scale power plants for cogeneration of multiple commodities. These plants may be built to deliver electricity, process steam, waste heat, and fresh water to industry or the general population. Another option is to use daily or even seasonal off-peak power to produce these commodities. Cogeneration or the use of off-peak power to level out the power demand can drastically improve the efficiency of power plants, making them more affordable, and making electricity cheaper. This study specifically looks at the use of off-peak power or cogeneration to desalinate brackish water or sea water. Nuclear electricity costs are examined here, but the use of off-peak power or cogeneration will work similarly for any steam cycle.

3C-3. AREAS OF INTEREST

The State of Texas has many different options for satisfying water demands in the coming fifty years. Water demands are expected to reach critical levels by 2010. The state is proposing to spend $17.9 billion over the next fifty years to increase the water supply through new wells, new reservoirs, and desalinization of coastal or brackish water.[24]

Texas currently has two nuclear plants in operation. Both sites have two units, and may be a logical location for additional nuclear generating capacity in the future. The first site (TXU) is Comanche Peak, about 4 miles north of Glen Rose, Texas. The second site (STP) is in South Texas, about 12 miles southwest of Bay City, Texas. This study looks at the economics of building new power generating capacity at a location similar to these that will be able to filter water to satisfy part of the future demand.

The *Water for Texas* study divides the state up into 16 regional water planning areas.[2] These areas

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23 *Desalting Handbook for Planners,* 3rd Edition, Desalination Research and Development Program Report No. 72, U.S. Department of the Interior (December 2002).

24 *Water for Texas*, Texas Water Development Board (January, 2002), available at www.twdb.state.tx.us .

are shown along with the location of the two nuclear plants in Figure 3C-2. Comanche Peak lies in Somervell County in the Brazos Region. The South Texas Project (STP) lies in Matagorda County in the Lower Colorado Region. The projected water demand increases for the two regions and all of Texas are shown in Table 3C-1. Water demand is expected to increase from 57.2 million m^3/day in 2000 to 67.7 million m^3/day in 2050 across the state. Existing water supplies in are expected to decrease from 60.3 million to 49.0 million m^3/day over the same period.

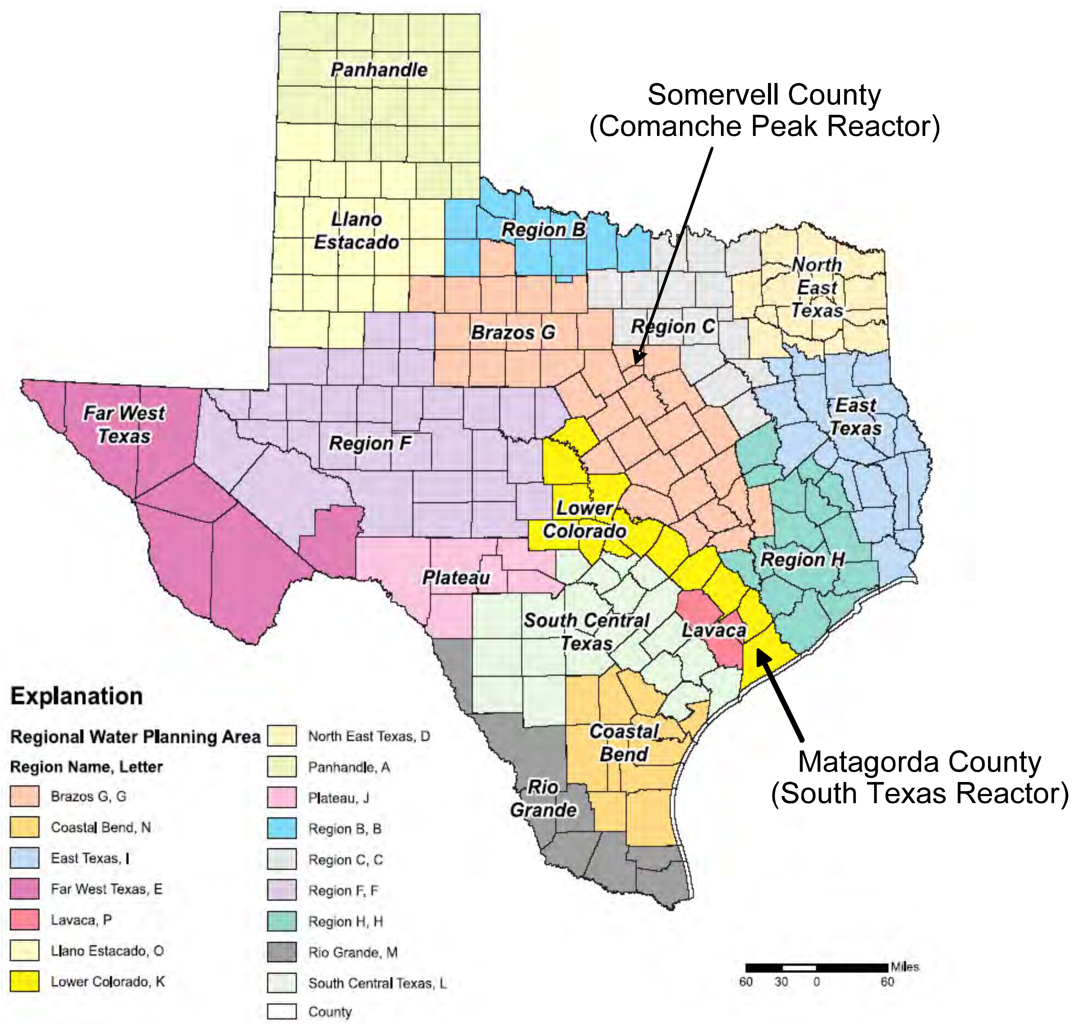

Figure 3C-2. Sixteen Regional Water Planning Groups in Texas[24]

Table 3C-1. Water Demand Projects in Texas (in m^3/day)[24]

(m^3/day)	2000	2010	2020	2030	2040	2050
Brazos: Region G	2,454,000	2,814,000	3,157,000	3,204,000	3,347,000	3,496,000
Lower Colorado: Region L	4,480,000	4,630,000	4,811,000	5,082,000	5,350,000	5,599,000
Texas Total	57,178,000	59,686,000	61,490,000	63,304,000	65,456,000	67,663,000

Figure 3C-3 shows the ground water quality across the state of Texas. The blue dots represent fresh water, yellow and orange represent mildly to moderately brackish water, and red represents highly brackish water. Both Somervell and Matagorda County have mostly fresh ground water supplies, so the reactors at these sites could not take advantage of brackish ground water. The Comanche Peak reactor in Somervell Country sits next to Squaw Creek Reservoir. This reservoir was designed solely for cooling of the reactor, and it cannot be used as a water supply. However, Lake Grandbury is located about 10 miles north of Comanche Peak and is a source of mildly brackish water. A Brackish Water Reverse Osmosis plant is currently being used to provide fresh water, but another plant may be supported. Cogeneration probably would not make as much sense as building a separate desalination plant at the source.

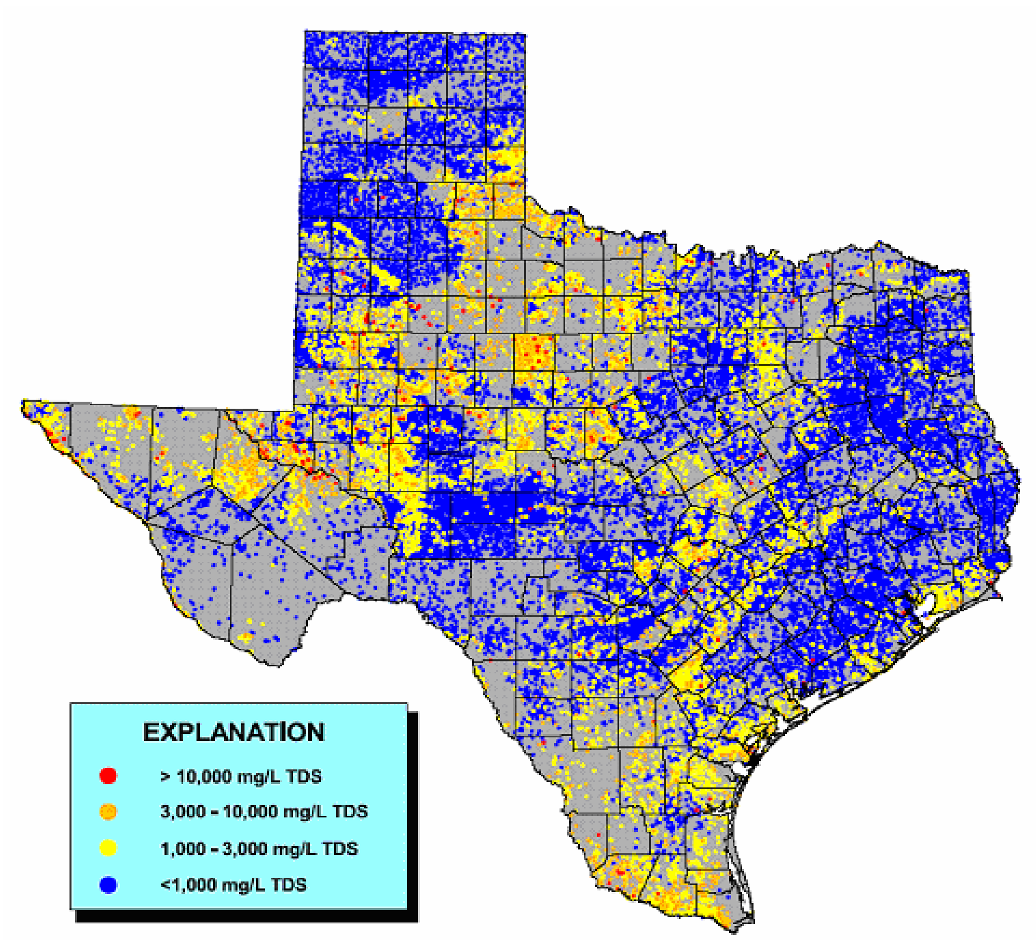

Figure 3C-3. Ground Water Quality in Texas[25]

The other option analyzed is the construction of new coastal power generation plants that can desalinate sea water. This option makes more sense for coupling desalination with power production because sea water is in virtually limitless supply, and the energy demands for sea water filtration are higher–leading to more cost savings. This option may make sense along the Gulf Coast. The distance from the coast to the South Texas Reactor in Matagorda County (about 10 miles) is such that it would probably be cheaper to build a separate desalination plant.

3C-4. WATER DESALINATION TECHNOLOGIES

The two major methods for desalting water are thermal distillation and reverse osmosis. Distillation processes heat seawater or brackish water to boil water vapor away from the impurities. This vapor

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25 *Brackish Groundwater Manual for Texas Regional Water Planning Groups,* Texas Water Development Board (February, 2003), available at www.twdb.state.tx.us .

is then condensed as pure water. Reverse osmosis uses pumps to force water through membranes that prevent most salts and impurities from passing. There are multiple ways to use each technology, and the final choice in design depends on many factors: the water source, the local demand and infrastructure, the availability of energy, etc. These many factors need to be taken into account when choosing the correct technology for an area.

The reverse osmosis technology is almost always the cheapest solution for water desalination. In 2002, about 91% of the desalting capacity in the United States was accomplished with reverse osmosis.[1] Saline water is pumped through membranes that prevent most of the impurities from passing. Sometimes more than one membrane may be needed to reach the desired concentration level. The bulk of the energy used in the process is pumping power, and the power requirement depends on the impurity concentration in the feed water. Feed water at 1200-1300 mg/L (mildly brackish water) will require about 12-15 bars of pressure and a pumping energy of about 0.5 kWh/m^3. Sea water at about 35,000 mg/L and above will require about 60 bars of pressure and a pumping energy of 4 kWh/m^3.[1] Reverse osmosis makes the most sense especially for brackish ground water with lower impurity concentrations.

The thermal distillation technologies in general are much more expensive to build than reverse osmosis. Of the thermal technologies, Multiple Effect Distillation (MED) is one of the cheapest. MED works by using steam to heat water in multiple effects or regions. Each effect vaporizes water at progressively lower pressures, taking advantage of the fact that water evaporates at lower temperatures as pressure decreases. The vapor from the first effect is used to heat the second effect, and so on. This configuration more fully utilizes the total heat input into the system.

The one advantage of distillation is that it can use waste heat generated from a power plant to power the system to increase the overall efficiency. Reverse osmosis requires pumping power which must draw off the main power feed. Reverse osmosis can use some of the waste heat to warm the water (which improves efficiency), but the overall power plant efficiency will not be as high as with thermal distillation. An economics analysis is shown in Section 6 that balances the increased capital and energy costs of thermal distillation with the savings in power plant efficiency.

3C-5. ELECTRICITY PRICES

3C-5.1. Texas Electricity Prices

Electricity prices follow a tier leveling scheme depending on the time of the day. A typical tier pricing scheme for industries in Texas receiving power from TXU Energy[26] is shown in Table 3C-2.

26 Rankine, B. (October, 2004), private communication, TXU Energy.

Table 3C-2. TXU Energy Prices[4]

Month	Pricing Period 4		Pricing Period 3		Pricing Period 3		Pricing Period 1
	Weekdays	Weekends	Weekdays	Weekends	Weekdays	Weekends	
December - March	N/A	N/A	N/A	N/A	6am - 12noon 6pm-10pm	N/A	All Other Hours
April, October & November	N/A	N/A	N/A	N/A	N/A	N/A	All Hours
May & September	N/A	N/A	2pm-8pm	N/A	10am-2pm 8pm-10pm	2pm-10pm	All Other Hours
June - August	2pm-8pm	N/A	10am-2pm 8pm-10pm	2pm-10pm	8am-10am 10pm-12mid	10am-2pm 10pm-12mid	All Other Hours

Period	$/kWh
1	$0.0563
2	$0.0681
3	$0.0746
4	$0.0874

For a constant electrical demand (all day long, all year long), this pricing scheme averages out to $0.0617/kWh. This graph shows that there is not a large incentive to only run during off-peak hours. Running only in the period 1 times drops the electricity costs to $0.0563/kWh, but this is not a significant savings from the year-round average (8.8%).

3C-5.2. Nuclear Power

Because the demand for fresh water is in the short-term, this project is looking at nuclear technologies that may be commercially available within the next ten years. Any new power plants built in that time frame will most likely be advanced light water reactors. The advantage of using nuclear power for this study is that it is carbon-free and does not depend on fossil fuel prices. Recently, rising natural gas prices have hurt industries in Texas, and building large coal-fired power plants is not environmentally desirable. Nuclear is the only other option for large base-load power plants. All of the economic analyses in this study assume an average daily electricity cost of $0.06 per kWh, which is close to the average cost of electricity in Texas, and for which nuclear energy should be competitive.[27]

3C-6. WATER DESALINATION PLANT COSTS

Three different desalination plants were analyzed for cost comparisons. Cost data for water filtration has been compiled in Footnote 23 using actual data as well as computer models in year 2000 dollars.

27 The Economic Future of Nuclear Power, University of Chicago (August, 2004), available at www.anl.gov/Special_Reports/NuclEconAug04.pdf .

The first plant is a Brackish Water Reverse Osmosis plant that desalinates mildly brackish ground water at 2500 mg/L dissolved impurities. The second plant is a Sea Water Reverse Osmosis plant that desalinates sea water. The final plant is a Multiple Effect Distillation plant that desalinates sea water. The analysis assumes a 100,000 m^3/day water production for all three cases. This plant size is fairly large, and economies of scale are about leveled out by this point.

3C-6.1. Brackish Water Reverse Osmosis (BWRO)

The BWRO plant is designed to purify brackish water with a dissolved impurity concentration less than 2500 mg/L. This concentration level is typical of many of the brackish ground water sources in Texas. The advantages of using brackish water are that the feed water may be found inland in many areas, and it is much cheaper than sea water desalination. The disadvantages are that the ground water supply may be limited, and it is more expensive to dispose of the concentrate. The capital and yearly costs are listed below.

Capital Costs (2000 Dollars)		million
BWRO Plant (includes desalting equipment, in plant piping, pumps & controls, pretreatment, post treatment, buildings/structures, cleaning system, electrical distribution, and indirect costs)		$35.0
Well Fields (800 ft deep)		$8.5
Concentrate Disposal (deep injection wells)		$9.0
Storage Tanks (one day storage)		$4.5
Transmission Pipeline (12,000 ft)		$7.0
	TOTAL CAPITAL COST	$64.0

Yearly Costs		million/year
Labor		$0.4
Chemicals		$1.0
Electricity (assumes $0.06/kWh)		$2.0
Membrane Replacement		$0.7
	TOTAL YEARLY COST	$4.1

Land costs are not included in this analysis since they can vary significantly with location. The additional capital costs besides the main plant can also vary quite a bit. Additional well depth, storage capacity, or pipeline length will increase costs. It is important to note that deep well injection of the concentrate may not always be possible. Concentrate disposal is a critical issue when building inland desalination plants, so BWRO may not be possible in some areas. Other disposal methods like evaporator ponds are prohibitively expensive for plants of this size.

For this reference 100,000 m^3/day BWRO plant, the total capital cost amounts to $64.0 million in the scenario shown. Assuming a plant life of 25 years and an interest rate of 7%, the amortized capital cost over the 25 year plant life is $5.5 million per year. Then the total yearly cost is $9.6 million, and 21% is due to electricity costs (most of which is used to run the pumps). Assuming a 90% capacity factor, the cost of water is $0.29/$m^3$. Actual year-2000 dollar cost of water data for a similar 57,000 m^3/day BWRO plant in Texas was $0.37/$m^3$.[3] Since the reference plant is larger and can take advantage of economies of scale, this analysis seems to be fairly close to actual data.

3C-6.2. Sea Water Reverse Osmosis (SWRO)

A SWRO plant at the same 100,000 m^3/day capacity costs considerably more due to the much higher salt content of sea water. Concentrate disposal is usually easier as it can be sent back to sea with negligible environmental impact. Yearly costs are higher mostly due to the increased electricity demand. The costs are listed below.

Capital Costs (2000 Dollars)	million
SWRO Plant (includes desalting equipment, in plant piping, pumps & controls, pretreatment, post treatment, buildings/structures, cleaning system, electrical distribution, and indirect costs)	$110.0
Intake Systems (screens, channel, etc.)	$5.0
Intake Pipe (3500 ft long)	$3.0
Concentrate Disposal (3000 ft long pipe)	$0.5
Storage Tanks (one day storage)	$4.5
Transmission Pipeline (12,000 ft)	$7.0
TOTAL CAPITAL COST	$130.0

Yearly Costs	million/year
Labor	$0.5
Chemicals	$2.2
Electricity (assumes $0.06/kWh)	$9.0
Membrane Replacement	$1.0
TOTAL YEARLY COST	$12.7

Altogether, the total capital cost for a 100,000 m^3/day SWRO plant is $130 million. The amortized payment using the 25 year plant life and 7% interest is $11.2 million per year. The yearly cost for operation and maintenance is $12.7 million. Then the total yearly cost is $24.1 million, with the cost of electricity accounting for 37% of this cost. The cost of water for this SWRO plant at a 90% capacity factor is $0.73/$m^3$.

3C-6.3. Sea Water Multiple Effect Distillation (SWMED)

A SWMED plant at the same 100,000 m^3/day capacity costs more than the reverse osmosis process in most categories. The base plant cost is quite a bit more expensive, and the energy costs are considerable. The costs are listed below.

Capital Costs (2000 Dollars)	million
SWMED Plant (includes desalting equipment, in plant piping, pumps & controls, pretreatment, post treatment, buildings/structures, cleaning system, electrical distribution, and indirect costs)	$140.0
Intake Systems (screens, channel, etc.)	$5.0

Intake Pipe (3500 ft long)	$2.7
Concentrate Disposal (3000 ft long pipe)	$1.4
Storage Tanks (one day storage)	$4.5
Transmission Pipeline (12,000 ft)	$7.0

TOTAL CAPITAL COST $160.6

Yearly Costs	million/year
Labor	$0.7
Chemicals	$5.0
Electricity for Processes (assumes $0.06/kWh)	$3.2
Steam (assumes $0.01/kWh thermal power)	$20.0
Repair and Maintenance	$3.0
TOTAL YEARLY COST	$31.9

Altogether, the total capital cost for a 100,000 m^3/day SWMED plant is $160.6 million. The amortized payment using the 25 year plant life and 7% interest is $13.8 million/year. The yearly cost for operation and maintenance is $31.9 million. Then the total yearly cost is $45.7 million, with the cost of energy accounting for 51% of this cost. The cost of water for this SWRO plant at a 90% capacity factor is $1.39/$m^3$.

Figure 3C-4 summarizes the economics analysis for the three types of plants and plots the cost of water as a function of interest rate. It is obvious that BWRO is the cheapest desalination plant. However, it can only be used in areas with plenty of brackish ground water supplies, and with the possibility open for deep well injection of the concentrate (or rejection into the sea). Near the coast, SWRO is the cheapest option.

Good supplies of fresh ground water (well water) in Texas can be cheap, with costs of water ranging from $0.08 to $0.19/$m^3$ depending on location.[28] Surface water prices range from $0.40 to $0.67/$m^3$. These costs are the actual production costs as opposed to the market price which will be higher. Using these numbers for comparison, BWRO can produce water at competitive prices. SWRO produces water at slightly higher prices, but in areas along the coast with limited fresh water supplies, desalination may be cheaper than piping water in across long distances. The thermal distillation processes are much more expensive.

28 Brunett, B. (October, 2004), private communication, Brazos River Authority.

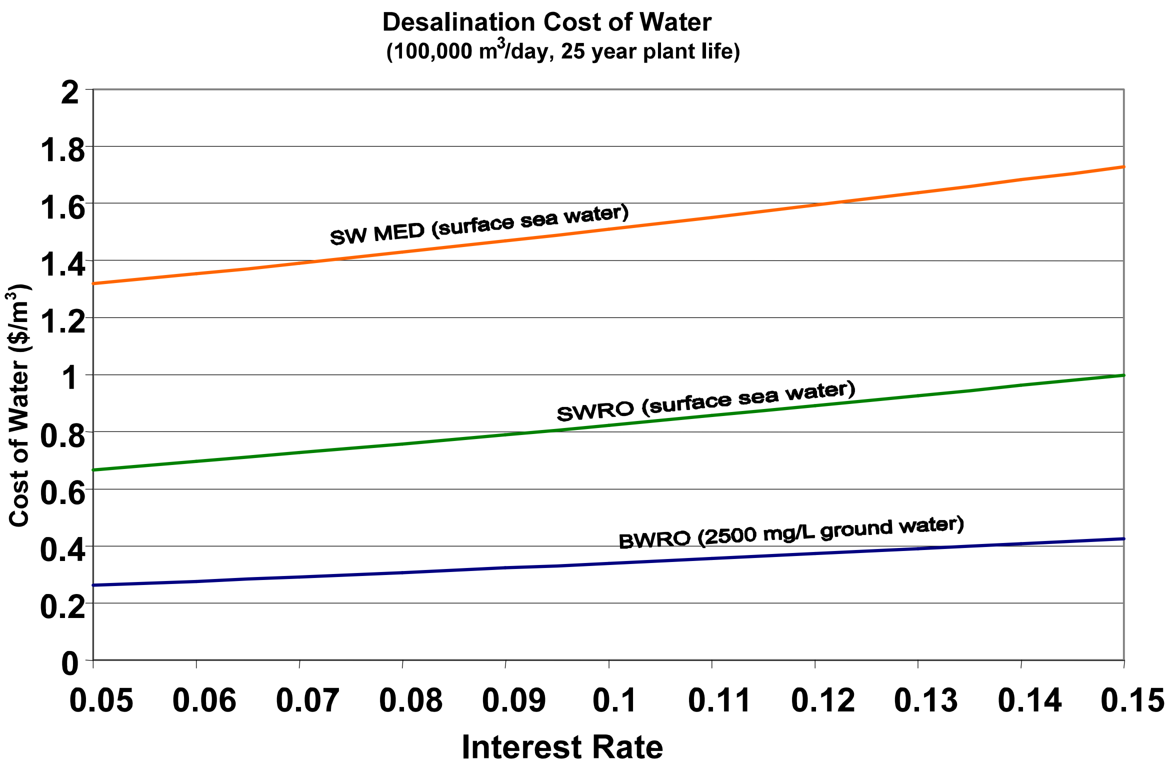

Figure 3C-4. Comparison of Costs of Desalination of Water

3C-7. WATER DESALINATION SCENARIOS

Three different scenarios were examined for how desalination can be implemented. The first scenario compares a desalination plant running at full capacity all day long to one running only during off-peak hours. The second scenario examines the use of cogeneration with a water desalination and power plant co-located. The third scenario examines a more innovative option of using energy storage to allow a water desalination plant to operate at full capacity while only drawing power during off-peak hours.

3C-7.1. Off-Peak Electric Use

The advantage of only using off-peak electricity for desalination is that it can lower costs if utilities will offer the electricity at a reduced rate. At the same time, it benefits power utilities by leveling out their demand curves and using capacity that otherwise would not be used. The main difficulty with this approach is that a majority of the cost of water from desalination is due to the capital costs of the plant. If the same size plant is built, but it can only operate at an average capacity of 50%, the cost of water will increase considerably.

Figure 3C-5 shows the cost of water for both BWRO and SWRO as a function of electric cost and water plant capacity factor. A typical average daily electricity price that utilities offer for anytime consumption is about $0.06 per kWh. For the BWRO plant operating at 50% capacity, the cost of water is always higher than the same plant operating at 90% capacity regardless of how cheap the electricity is. For this situation, it does not work out to only run the water desalination plant at night. With the SRWO plant, the same trend is followed. Even with free electricity and running at half capacity, the cost of water for both concepts would be higher than if the plants paid full price and ran all day long. There is no economic incentive for the desalination plant to only run during off-peak hours.

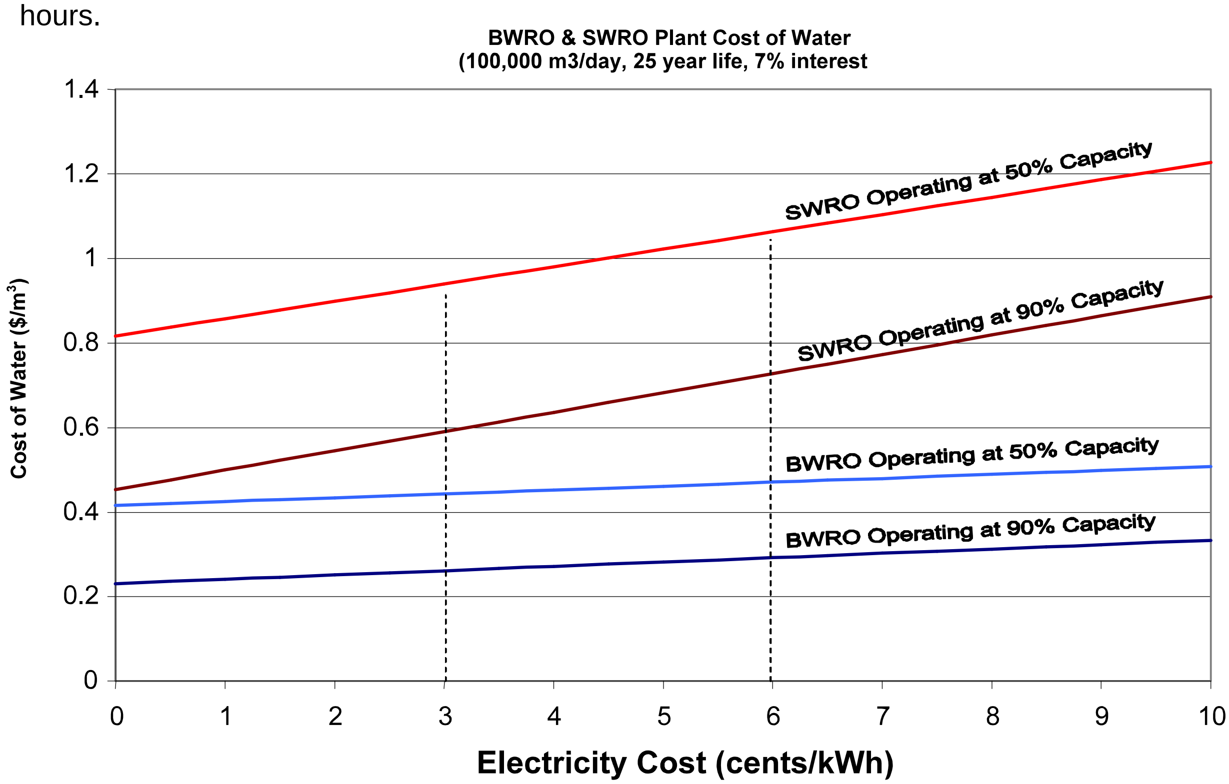

Figure 3C-5. Water Costs as a Function of Capacity Factor

3C-7.2. Cogeneration

It is possible to couple water desalination with power production in a cogeneration style power plant. The main benefit of cogeneration is a higher overall system efficiency which decreases power plant costs. In addition, by building both plants together, there will be cost savings in capital for infrastructure. For example, for desalting sea water at a coastal power plant, the same input and output water lines used for the power plant can be used to bring in the water for desalination.

The drawback of cogeneration is that the water filtration plant must co-locate with the power plant. This requirement is not always practical, especially since many power plants are located a fair distance from a city (where water demand is greatest). In the case of nuclear power, there may be unforeseen political problems with desalting water using the cooling water that is used for a nuclear reactor.

In order for cogeneration to make feasible sense, the increased efficiency must make up for the increases in capital costs for building the coupled system. Another way to look at the problem is to determine the difference between building a separate power plant and water desalination plant compared to building the combined plant.

The EURODESAL project[29] investigated the use of nuclear and coal power plants for water desalination in a cogeneration style plant. A 900 MWe pressurized water reactor was used for the analysis, and waste heat was used to power desalination in a thermal distillation process (Multiple Effect Distillation). The study found that to produce 216,000 m^3/day of fresh water (from sea water) required about 402 MW of thermal energy taken from the steam cycle. This back end use resulted in the loss of 51 MWe of shaft power. The desalination plant costs for this size are shown below.

Capital Costs (2000 Dollars)	million
SWMED Plant (includes desalting equipment, in plant piping, pumps & controls, pretreatment, post treatment, buildings/structures, cleaning system, electrical distribution, and indirect costs)	$280.0
Intake Systems (screens, channel, etc.)	$9.0
Intake Pipe (3500 ft long)	$4.0
Concentrate Disposal (3000 ft long pipe)	$2.0
Storage Tanks (one day storage)	$8.0
Transmission Pipeline (12,000 ft)	$14.0
TOTAL CAPITAL COST	$317.0

Yearly Costs	million/year
Labor	$0.9
Chemicals	$11.0
Electricity for Processes (assumes $0.06/kWh)	$6.4
Steam (assumes $0.01/kWh thermal power)	$43.2
Repair and Maintenance	$6.0
TOTAL YEARLY COST	$67.5

The costs shown in italics are those that are eliminated with cogeneration. By using the power plant intake and rejection water system, the capital cost savings amount to $15 million. The electricity and steam costs are saved because the cogeneration plant will not “charge itself” for the energy. However, assuming the power plant could have sold all of that 51 MWe of lost electric power at normal electricity rates ($0.06/kWh), the plant is losing $26.8 million per year. The cost of water must make up for the lost electric revenue, added capital costs, and added yearly costs.
Likewise, the same analysis was completed for a SWRO plant that uses cogeneration. The difference is that reverse osmosis must use electric power directly from the plant. It can, however, use the waste heat to warm up the incoming sea water. Warmer water will make the membrane process more efficient. Increasing the feed sea water temperature from 25ºC to 45ºC allows the pressure requirement to drop from 69 bars to 62.1 bars for the same water production.[1] This leads to a savings

29 Nisan, S. et al. “Sea-Water Desalination with Nuclear and Other Energy Source: The EURODESEAL Project,” *Nuclear Engineering and Design*, **221**, 251 (2003).

of about 0.4 kWh/m^3 of pumping power and decreases electricity requirements by 10%. The costs for a 216,000 m^3/day SWRO plant are shown below.

Capital Costs (2000 Dollars)	million
SWRO Plant (includes desalting equipment, in plant piping, pumps & controls, pretreatment, post treatment, buildings/structures, cleaning system, electrical distribution, and indirect costs)	$200.0
Intake Systems (screens, channel, etc.)	$10.0
Intake Pipe (3500 ft long)	$4.8
Concentrate Disposal (3000 ft long pipe)	$0.8
Storage Tanks (one day storage)	$8.0
Transmission Pipeline (12,000 ft)	$14.0
TOTAL CAPITAL COST	$237.6

Yearly Costs	million/year
Labor	$0.6
Chemicals	$5.0
Electricity (assumes $0.06/kWh)	$20.0
Membrane Replacement	$2.0
TOTAL YEARLY COST	$27.6

The capital costs in italics are eliminated with cogeneration, and the yearly electric cost in italics is decreased 10% for cogeneration. Both the SWMED and SWRO cost of water with and without cogeneration is shown in Figure 3C-6. This figure assumes a desalination plant life of 25 years with 90% capacity factor, and varying interest. There is a slight difference in the cost of the reverse osmosis plant when cogeneration is used. The price at 7% interest drops from about $0.68 to $0.63/$m^3$ for SWRO cogeneration (a 7% savings in cost). There is a larger drop in price using the SWMED process, but these costs are still well above the SWRO process. The price at 7% interest drops from $1.33 to $0.96/$m^3$ for SWMED cogeneration.

Clearly, reverse osmosis continues to be the technology of choice. Although the thermal distillation processes are able to use thermal waste heat to desalinate water, the energy requirements are so much more than reverse osmosis that it does not make up for the high cost. The 216,000 m^3/day SWMED plant requires 402 MWth and 12 MWe altogether. The 216,000 m^3/day SWRO plant requires 38 MWe altogether. It is a much more efficient use of energy to use the reverse osmosis process.

A 100,000 m^3/day BWRO water desalination plant uses 3.8 MWe during full operation while a 100,000 m^3/day SWRO plant uses about 17.6 MWe. In the Brazos Region (Region G), the water demand across the entire region is expected to increase by 1,000,000 m^3/day by the year 2050. If all of this water demand were met by desalination, the energy demands would be anywhere from 38 to 176 MWe (BWRO vs. SWRO) depending on the type of water desalinated. Therefore, one large 1000 MWe power plant in 50 years would be able to provide plenty of power to satisfy the increase in demand. The difficulty with cogeneration is that the demand increase is spread over many counties; it may be too much water to produce in one location. Also, cogeneration usually requires constant water production to balance the heat cycle, so it may not be possible to use it for off-peak energy use.

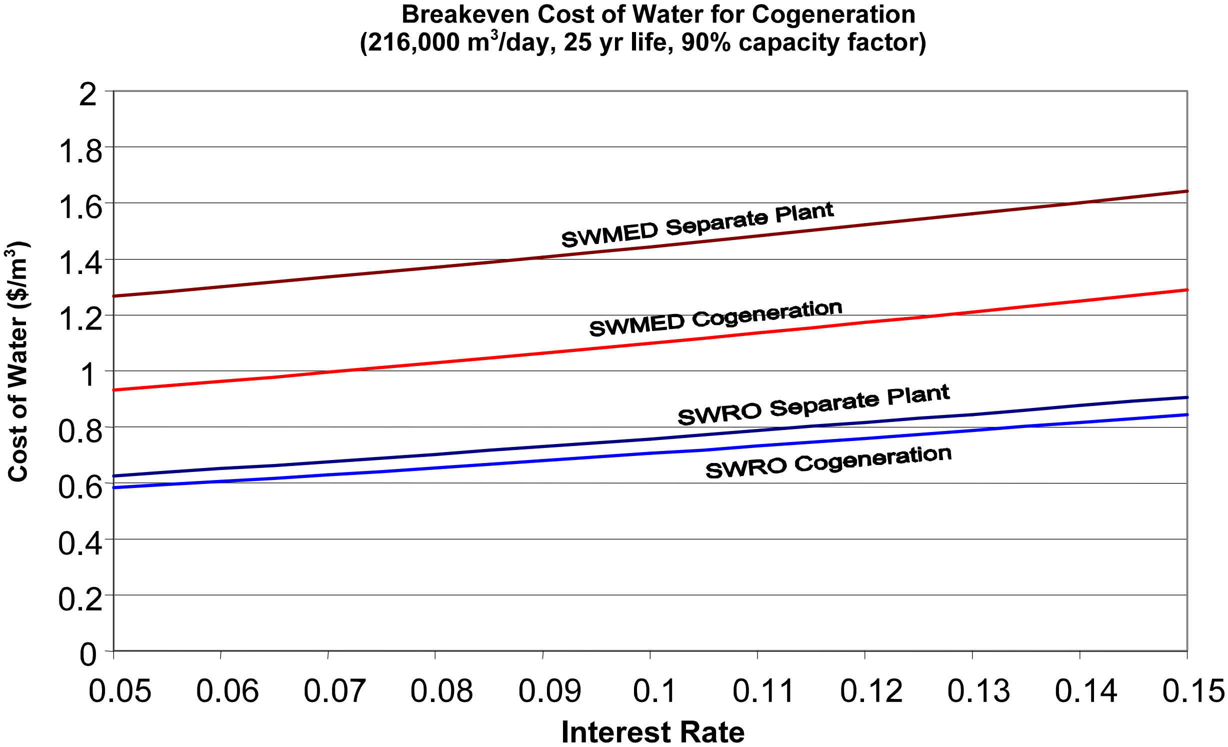

Figure 3C-6. Cogenerated Water Cost Savings

3C-7.3. Off-Peak Electric Use with Energy Storage

It may be possible to build desalination plants that operate at full capacity but only use off-peak power. This option may make sense in select areas by utilizing energy storage technologies. One particular large-scale energy storage system, called pumped hydro, pumps water from a lower reservoir to a higher reservoir. Energy is stored as the potential energy of water and can be extracted at a later time.[30]

Pumped hydro may make sense to couple with water desalination since the stored energy is already in the form needed for reverse osmosis: water pressure. The idea is to build a desalination plant with a double set of pumps. During full off-peak hours, half of the excess energy is used to pump water through the desalination plant membranes at the full plant capacity. At the same time, the other half of the plant excess is being used to pump water to an uphill reservoir (see Figure 3C-7). Then, during peak demand times when the power plant has no power to give up, the reservoir is drained through the reverse osmosis membranes. With this system, it may be possible to design the filtration plant to run at full capacity while only drawing the excess off-peak power from a power plant.

30 Denholm, P. *Environmental and Policy Analysis of Renewable Energy Enabling Technologies*, Ph.D. Thesis, University of Wisconsin-Madison (2004).

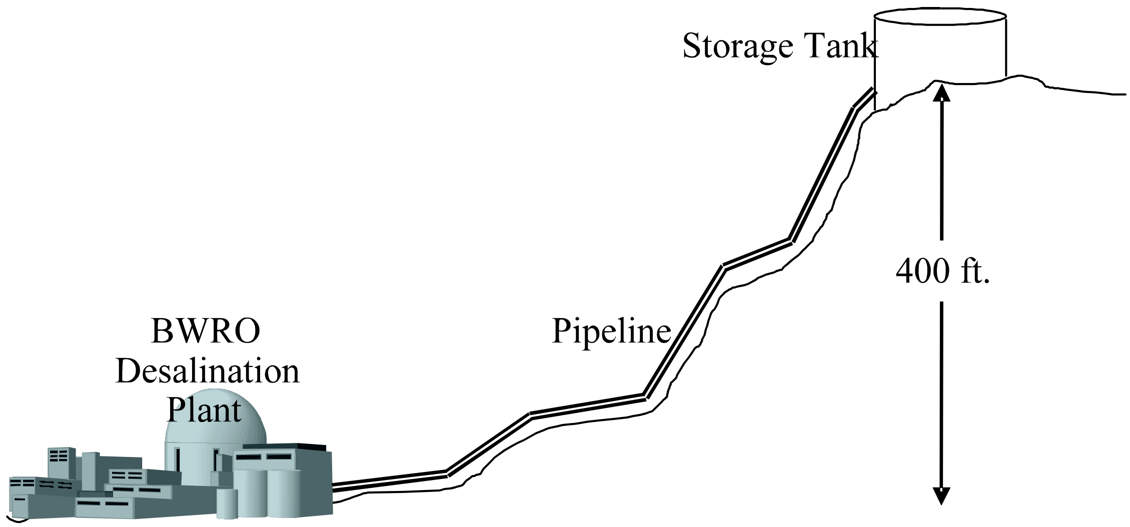

Figure 3C-7. Pumped Hydro Energy Storage Concept

This desalination concept does not need to be located near a power plant. The concept may allow a desalination plant to be built to only run during off-peak hours to take advantage of low electricity rates. The economic analysis involves balancing the off-peak electricity cost savings with the cost of added pumps and the reservoir system. Because large elevation drops are required to reach the appropriate pressures, this option may only make sense in certain areas (near a hill for example) where a water storage tank can be cheaply built at the right height above the desalination plant.

The added capital costs for energy storage include additional pumps, an additional pipeline to the upper reservoir, and the reservoir cost. The assumption made here is that the desalination plant is located in an area with an elevation rise. Additional land costs will not be taken into account. Since about 400-500 ft of water head will be needed to maintain the appropriate pressure, it would be too costly to build a water tower.

An additional set of pumps to supply 100,000 m^3/day will cost about \$1 million. A 100,000 m^3 storage tank will cost about \$4.5 million. Assuming 1 mile to reach the reservoir, the pipeline will cost about \$3 million. Assume another \$1 million may be needed for control systems. Altogether, the capital cost of the plant increases by \$9.5 million. Note that this only applies to the BWRO type plant which requires lower pumping pressures than SWRO. Figure 3C-7 shows the increase in cost of water as a function of electric costs for this energy storage concept.

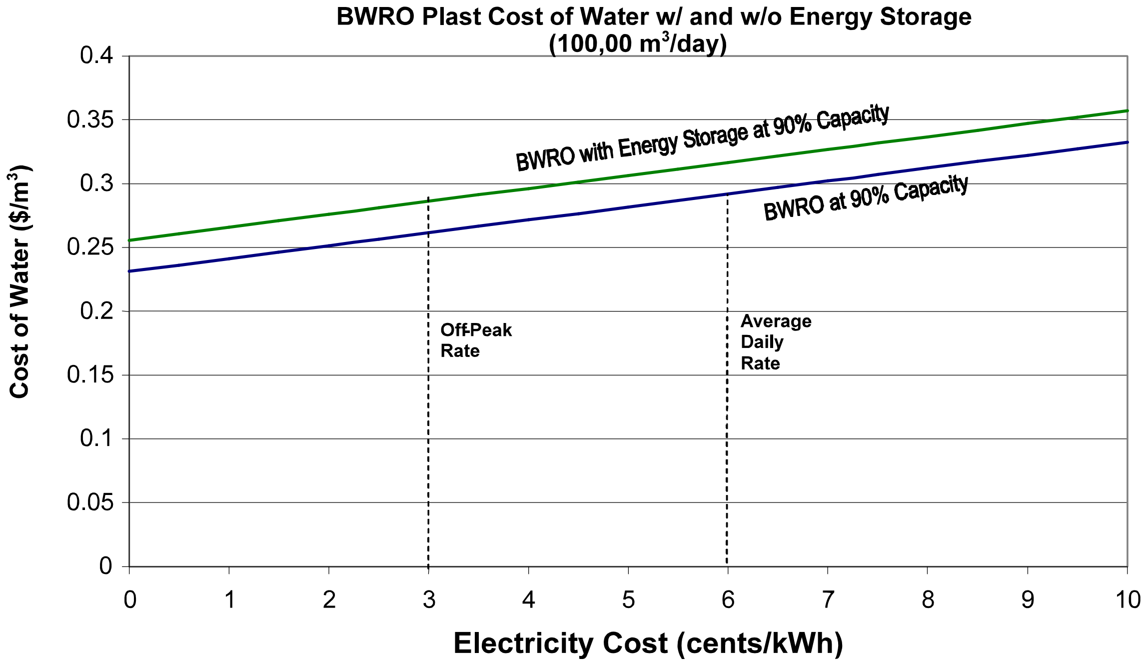

Figure 3C-8. BWRO Energy Storage Option

The figure shows that in order for the cost of water to be comparable, the BWRO plant with energy storage would have to get off peak electricity from the power plant at about half of the average daily rate. For example, if the average daily rate of electricity is $0.06/kWh, and the desalination plant can get power at night for $0.03/kWh, the cost of water is about the same for both options at $0.29/m^3. With water costs about the same, this option may help to level out electric load demand throughout the day. Note that the price breakdowns for electricity in Texas shown in Table 3C-2 do not vary enough to make this energy storage option worth the extra initial capital cost.

Energy storage using pumped hydro is probably not feasible for SWRO. The filtering of sea water requires much higher pumping powers and pressures, so it would require a reservoir 1500 to 2000 ft above the level of the water filtration plant. It would be exceedingly difficult to find the right geography to match this need.

3C-8. CONCLUSION

Existing water supplies in Texas are expected to decrease from 60.3 million m^3/day in 2000 to 49.0 million m^3/day in 2050. Over the same period, water demand is expected to increase from 57.2 million to 67.7 million m^3/day across the state. *The cost of production of ground water is currently between $0.08 and $0.19 per m^3 while surface water costs between $0.40 and $0.67 per m^3. Depending on the source, desalination is already or soon will be competitive with traditional supplies.*

Since the cost of water produced by Reverse Osmosis is in the competitive range of fresh surface water, there are many areas that would be in the market for water produced by reverse osmosis. 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.*

A BWRO desalination plant is by far the cheapest technology for inland water desalination and is competitive with current water costs at \$0.29/m^3. However, it can only be used if there are adequate supplies of brackish ground water and if deep well injection or sea disposal of the concentrate can be done. This may be possible in select inland areas of Texas with little fresh water available. SWRO is the cheapest and most energy efficient way to desalt sea water at \$0.73/m^3. Cogenerated power and water desalination can drop the price of water a fair amount and save a little on energy use. The two current locations of nuclear plants in Texas probably could not be used for cogeneration of water. In both cases it would make more sense to build separate desalination plants due to source considerations. Cogeneration may make the most sense in the Gulf Coast area of Texas that has industries that want cheap power/steam and plenty of sea water to desalinate. In addition, cities near the coast with large energy demands also will have large water demands.

The running of water desalination plants only during off-peak power production always will drive up the cost of water due to running the plant at lower capacity factors. The cost of water is cheaper when the plant can run at full capacity all day long. A water desalination plant will want to run at full capacity in the current economic environment.

The one possible solution for using up off-peak power is through energy storage using pumped hydro. This solution may only work in a select few areas where a BWRO plant can be built at a suitable location with an elevation rise. Even then, the water desalination plant would have to be able to get electricity (during off peak hours) for about half of the average daily rate.

APPENDIX 3D: CONTINGENCIES AS A FUNCTION OF THE LEVEL OF ENGINEERING DETAIL

Table 3D-1. Contingencies as a Function of the Level of Engineering Detail

AACEI Project Stage	AACEI Suggested Contingency	EPRI Project Stage	EPRI Suggested Contingency
Concept screening	**50%**		
Feasibility Study	**30%**	Simplified Estimate	30% to 50%
Authorization or Control	**20%**	Preliminary Estimate	15% to 30%
Control or Bid/Tender	**15%**	Detailed Estimate	10% to 20%
Check Estimate or Bid/Tender	**5%**	Finalized Estimate	5% to 10%

TASK 4 APPENDIX

APPENDIX 4A. LICENSING OPTIONS EVALUATION

Table 4A-1. Evaluation of the Licensing Options

COL Options--All include site licensing

Licensing CTQs	Combined Weighting	Metric	Option1: Reference existing DC	Option 2: Reference DC application	Option 3: COL includes design licensing
Shortest amount of time to get COL	0.82	Expected value in months compared to 24 months	6.67	6.67	4.00
Least risk of COL being delayed	0.88	One standard deviation away from the mean, months	10	5	1
Shortest overall project schedule	0.83	Expected value in months compared to 72 months	10	10	7
Least risk of overall project delay	0.95	One standard deviation away from the mean, months	10	5	1
Lowest cost to get COL	0.47	Expect value of cost compared to $25M	10	10	7
Lowest cost to get plant into operation	0.52	Cost to complete in USD, compared to Expected Value of capital costs	10	9	5
TOTAL			42	32	17
NORMALIZED			100%	76%	40%

Data		Option 1	Option 2	Option 3
Shortest amount of time to get COL	Months	36	36	60
One standard deviation away from the mean	Months	1	6	12
Shortest overall project schedule	Months	Reference	Same	Adds 30%
One standard deviation away from the mean	Months	1	6	12
Cost to obtain COL	$M	$15.00	$15.00	$20.00
Lowest cost to get plant into operation	$M	No effect	Same	Same

Table 4A-1. Evaluation of the Licensing Options (Continued)

CTQs	Weighting	Metric	Metric explained	Shortest amount of time to get COL	Least risk of COL being delayed	Shortest overall project schedule	Least risk of overall project delay	Lowest cost to get COL	Lowest cost to get plant into operation
Low Cost	9.33	$33.33	$ Per MHWR or some 10% below market	5	5	10	10	5	10
Cost Stability	7.96	6.38	Cost stability as measured by max. length of PPA in years	1	1	1	1	1	10
Few Service Interruptions	7.08	8.36	Tolerable service interruptions per year	1	1	1	1	1	1
High Power Quality	6.20	2.58	High Power Quality. 1= grid ok, 5=high nines	1	1	1	1	1	1
Flexibility to meet load profile	6.08	2.00	Flexibility to meet load profile, 1=won't pay any premium; 5=will pay premium	1	1	1	1	1	1
Less usage of natural gas	10.00		Reduce prices of natural gas as much as possible as soon as possible	5	5	10	10	1	1
Predictable start of supply	4.67	9.00	Start of supply within "X" months of contract date	5	5	10	10	1	1
Supplier portfolio	5.92	3.80	Supplier portfolio/credit worthiness	1	1	5	5	1	5
Air emission offsets	3.33	1	Air emissions	5	5	10	10	1	1
Other–write in	4.00	4.00	Customer service, 1 comment	1	1	5	5	1	1
	TOTAL Normalized			174 0.50	174 0.50	350 1.00	350 1.00	102 0.29	244 0.70

Table 4A-1. Evaluation of the Licensing Options (Continued)

CTQs	Weighting	Metric	Metric explained	Shortest amount of time to get COL	Least risk of COL being delayed	Shortest overall project schedule	Least risk of overall project delay	Lowest cost to get COL	Lowest cost to get plant into operation
Higher Return on Invested Capital	7.60	>15%	15% is the approximate weighted average cost of capital for potential investors. Because of the risk associated with this project, a higher return is needed to make the investment appealing.	9	9	10	10	5	10
Acceptable Bondholder investment horizon	7.00	10-14 years max	Debt holders do not want to be exposed to risk longer than 10 to 14 years	7	7	10	10		
Project meets NRC Financial Policy for Nuclear Plants	9.20	Go/No-GO							
Predictable Cash flow/value	8.50	Coefficient of variation <0.2	The common measure for cash flow variability	3	5	5	8	5	5
Minimal development costs	6.20	Debt to Equity Ratio of 80/20		10	10	3	3	10	3
High Leveraged Financing	7.40	Probability of extended shutdown <0.1% a year	The higher the ratio, the more profitable the plant. Increase debt up to the point where equity costs begin to increase.	3	3	3	3	3	3

Table 4A-1. Evaluation of the Licensing Options (Continued)

CTQs	Weighting	Metric	Metric explained	Shortest amount of time to get COL	Least risk of COL being delayed	Shortest overall project schedule	Least risk of overall project delay	Lowest cost to get COL	Lowest cost to get plant into operation
Manage Unique Risks	9.80		No extended shutdowns expected during 60-year life of plant from either technology or licensing concerns.						
Early public acceptance	9.25	$3M a year from year 1	Expenditure of time and money to engage community, environmental, and other interest groups.	7	7			5	
Certainty of plant entering commercial operation as planned	10			5	7	7	10		
Resolution of Current Nuclear Waste Issues	8.5								
	TOTAL			**325 0.93**	**351 1.00**	**272 0.78**	**326 0.93**	**183 0.52**	**161 0.46**

APPENDIX 4B. TABLE OF CONTENTS FOR THE COL APPLICATION

Section	Subsection	Reference
TRANSMITTAL LETTER	**CONTENTS** - Request for license - Oath and Affirmation	10 CFR § 52.75, § 50.30(b)
APPLICATION	**GENERAL INFORMATION** - Institutional Information - Financial Qualifications	10 CFR § 52.77, § 50.33
APPENDIX A	**ANTITRUST INFORMATION** (To be submitted 9 months prior to the COL application)	10 CFR § 52.77, § 50.33a, Part 50 App. L
APPENDIX B	**FINAL SAFETY ANALYSIS REPORT**	10 CFR § 52.79, § 50.34(b)
APPENDIX C	**EMERGENCY PLAN**	10 CFR § 52.77, § 50.33(g), § 50.47
APPENDIX D	**FIRE PROTECTION PLANT** - Fire hazards Analysis	10 CFR § 50.48(a), Appendix R.II to 10 CFR Part 50, RG 1.70 Section 9.5.1
APPENDIX E	**SECURITY PLAN**	10 CFR § 52.79, § 50.34(c), 10 CFR Parts 11 & 73, Appendix C
APPENDIX F	**SAFEGUARDS CONTINGENCY PLANT**	10 CFR § 52.79, § 50.34(d), 10 CFR Part 73
APPENDIX G	**DESIGN-SPECIFIC PROBALISTIC RISK ASSESSMENT**	10 CFR § 52.79(b), § 52.47(a)(1)(v)
APPENDIX H	**ENVIRONMENTAL INFORMATION**	10 CFR § 52.79, § 52.89, § 50.30(F), §51.45, §51.50
APPENDIX I	**ITAAC**	10 CFR § 52.79(c)
APPENDIX J	**TECHNICAL SPECIFICATION**	10 CFR § 52.79, § 50.34(B)(6)(VI), § 50.36
APPENDIX K	**EXEMPTION REQUESTS** (as necessary)	10 CFR §50.12
APPENDIX L	**REQUEST FOR WITHOLDING OF TRADE SECRETS, AND COMMERCIAL OR FINANCIAL INFORMATION** (as necessary)	10 CFR § 2.790

APPENDIX 4C. PROPOSED MILESTONE SCHEDULE FOR COMBINED OPERATING LICENSE PROCEEDING (Referencing a Design Certification or Design Certification Application)

Step	Milestone	Schedule Duration Best Estimate	Regulatory Basis
1	Begin scoping/preparation of application.	-24 months	
2	Begin pre-application review with NRC.	-18 months	A pre-application review is not required but is encouraged by NRC.
3	Applicant submits anti-trust in information to NRC.	-9 months	10 CFR § 50.33(a)(6). Antitrust portion of application must be filed at least 9 months but no more than 36 months prior to the rest of the application.
4	NRC holds public meeting near site to inform public of COL process.	-6 months	NUREG/BR-0073, Rev.1, p. 2-1
5	Applicant submits COL application		
6	NRC publishes a notice in the Federal Register starting that the application has been received and copies are available in the PDR.	+1 month	No time limits are provided for this notice but this notice has normally been published within 4 weeks of docketing ESP applications.
7	NRC determines whether the application is acceptable for docketing as a sufficient COL application.	+1 month, 1 week	10 CFR § 2.101(a)(2). This preliminary docketing review has generally been complete within 5 weeks of submission of an ESP.
8	NRC publishes a notice in the Federal Register of it intent to prepare an EIS on the COL application and conduct public environmental scoping meeting.	+2 months	10 CFR §§ 51.26 and 51.27(a). No time limits are provided for notice of intent to prepare an EIS but this notice has normally been published within 8 weeks of submitting an ESP application.
9	NRC publishes a notice in the Federal Register of an opportunity for a hearing on the COL application.	+2 months, 3 weeks	10 CFR § 2.104. This notice must be provided at least 30 days prior to the date set for hearing and has generally been provided within 10-11 weeks of filing an ESP application.

APPENDIX 4C. PROPOSED MILESTONE SCHEDULE FOR COMBINED OPERATING LICENSE PROCEEDING (Referencing a Design Certification or Design Certification Application)

Step	Milestone	Schedule Duration Best Estimate	Regulatory Basis
10	NRC conducts public environmental scoping meeting.	+3 months	10 CFR §§ 51.27 and 51.28. No time limits are provided but this meeting has normally been held for ESPs within 3-4 weeks of the meeting notice.
11	Environmental scoping period ends.	+4 months	10 CFR § 51.29. No time limits are provided but the scoping period has normally been closed for ESP applications within 3-4 weeks of the environmental scoping meeting.
12	Interested parties submit requests for hearing on COL application	+4 months, 3 weeks	10 CFR §2.309. Normally within 60-days of publication of opportunity for hearing, unless a different period is specified by the Commission.
13	NRC staff issues requests for additional information (RAIs) on environmental issues.	+7 months	Environmental RAIs for ESP applications have normally been issued with 6-8 months of receipt of the application.
14	NRC staff issues RAIs on site and plant specific safety issues.	+10 months	Safety RAIs for ESP applications have normally been issued within 9-11 months of receipt of the application.
15	NRC receives responses to environmental RAIs from applicant.	+10 months	Responses to environmental RAIs in ESP applications have been submitted to NRC 10-16 weeks after receipt.
16	NRC issues Federal Register notice of availability of draft environmental impact statement and request for comments.	+14 months	10 CFR §§ 51.70 - 51.74. No time limits are provided but the draft EIS for ESP applications are scheduled to be issued within 4 months after applicant responds to environmental RAIs or within 14 months of submitting the application.
17	NRC conducts public meeting to discuss draft EIS.	+15 months	Meetings for Esp applications are scheduled to be held 30- 45 days of publication of the draft EIS.

APPENDIX 4C. PROPOSED MILESTONE SCHEDULE FOR COMBINED OPERATING LICENSE PROCEEDING (Referencing a Design Certification or Design Certification Application)

Step	Milestone	Schedule Duration Best Estimate	Regulatory Basis
18	NRC receives responses to site and plant specific safety RAIs from applicant.	+16 months	Responses to safety RAIs have normally been submitted to NRC within 10 weeks after receipt in ESP applications. However, given the broader scope fo the COL, additional time may be required to respond to the safety RAIs.
19	Public comment period on draft EIS ends	+16 months, 2 weeks	10 CFR § 51.73. A minimum 45-day comment period is required. ESP applications are scheduled for a 10-week EIS comment period.
20	NRC issues draft SER on site and plant specific safety issues. (with open items).	+20 months	The draft SER for ESPs are scheduled to be issued within 4 months after applicant responds to safety RAIs.
21	ACRS subcommittee meeting on draft SER	+20 months, 3 weeks	ACRS subcommittee meetings for ESPs are scheduled to be held within 3 weeks of issuance of draft SER.
22	Full ACRS meeting on draft SER site and plant specific safety issues	+21 months, 1 week	Full ACRS meetings for ESPS are scheduled to be held within 2 weeks of the subcommittee meeting.
23	NRC issues final EIS.	+22 months	The final EIS for ESPs is scheduled to be issued within 5 months ofo the end of the draft EIS comment period.
24	Hearings begin on environmental items.	+23 months	
25	Applicant responds to SER open itmes	+24 months	Responses to SER open items for EPS are scheduled to be submitted within 10-12 weeks of issuance of the draft SER.
26	Hearings end on environmental issues.	+24 months	This period will be dependant on the number and complexity of contentions and capabilities of interveners. The actual duration could be shorter or significantly longer.

APPENDIX 4C. PROPOSED MILESTONE SCHEDULE FOR COMBINED OPERATING LICENSE PROCEEDING (Referencing a Design Certification or Design Certification Application)

Step	Milestone	Schedule Duration Best Estimate	Regulatory Basis
27	NRC issues final SER site and plant specific safety issues.	+28 months	The final SER for ESPs is scheduled to be issued within 3-4 months of receiving responses to open items.
28	NRC issues Federal Register notice of availability of final SER.	+28 months, 1 week	
29	Hearings begin on site and plant specific safety issues	+29 months	
30	Full ACRs meeting on final SER.	+30 months, 2 weeks	The full ACRS meeting on the final SER for ESPs is scheduled to be held within 10 weeks of the final SER.
31	ACRS Letter.	+31 months	10 CFR § 52.87. No time limits are provided but the ACRS letter for ESPs is scheduled to be issued within 2 weeks fo the full ACRS meeting.
32	Hearings end on site and plant specific safety issues	+31 months	This period will be dependant on the number and complexity of contentions and capabilities of interveners. The actual duration could be shorter or significantly longer.
33	ASLB issues initial decision on COL.	+34 months	There is not time limit in new Part 2 regulations. However, given the Commission’s focus on timeliness, 90 days is a reasonable assumption.
34	NRC staff issues COL following Commission review	+36 months	10 CFR § 2.340 (f)(2) states that the Commission will seek to issue a decision within 60 days of the ASLB initial decision.

Assumptions: Some of the time periods provided above are longer than the corresponding periods for ESPs, because they safety issues may be more complex with COLs.

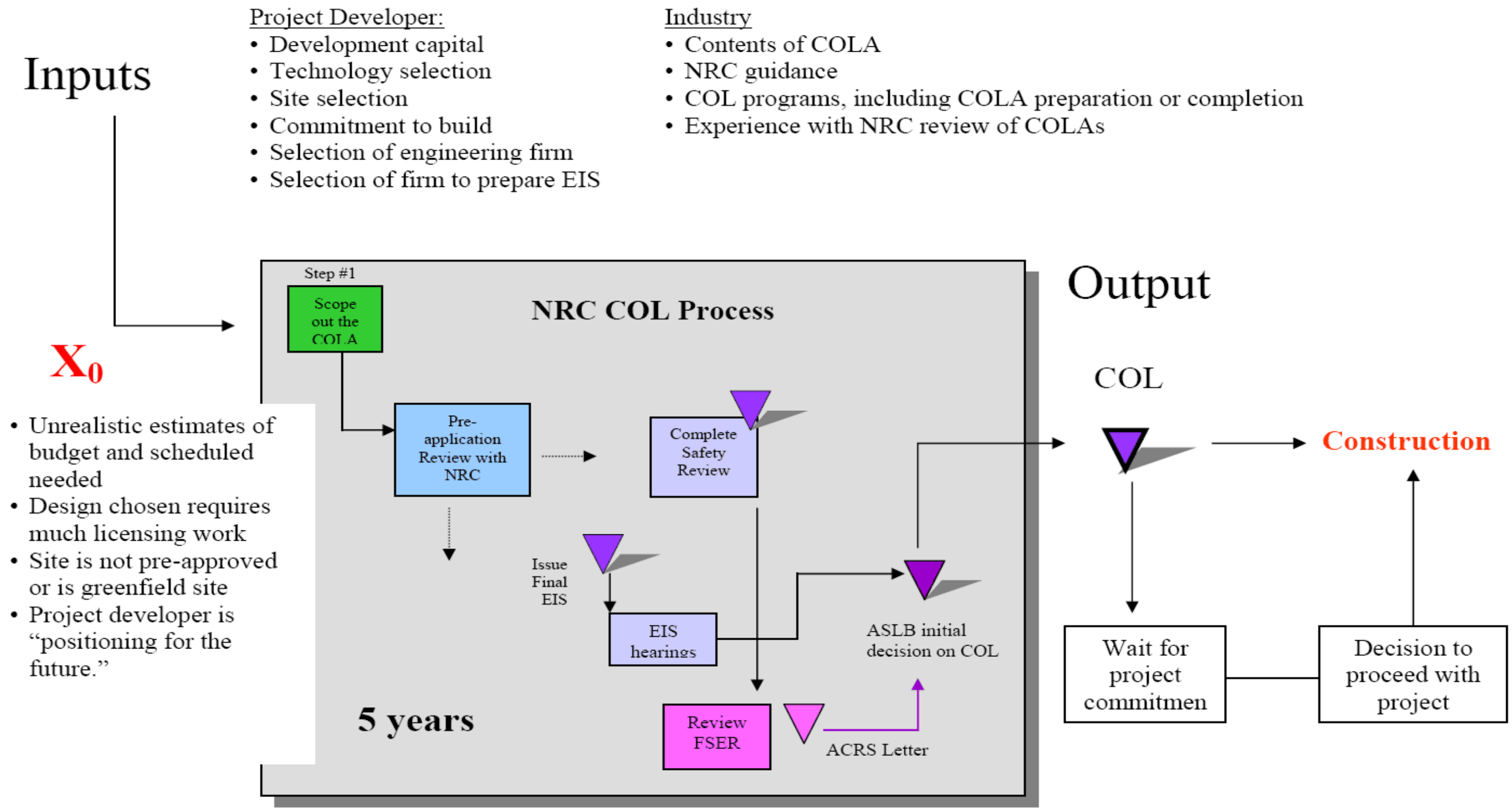

Figure 4C-1. The Project Developer's COL Process

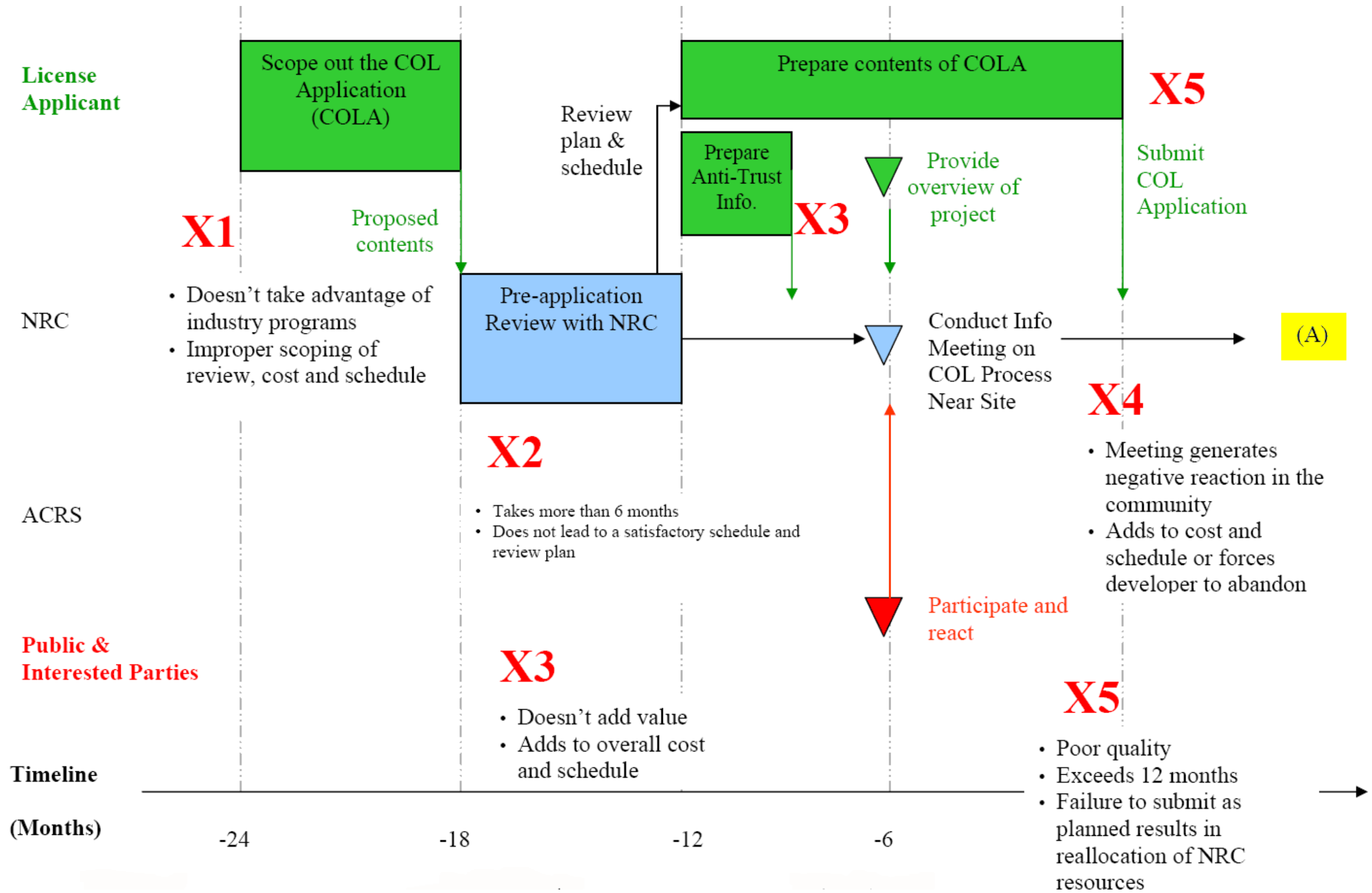

Figure 4C-2. Process Map for NRC's Combined Operating License Proceeding Critical Xs for Six Sigma Analysis

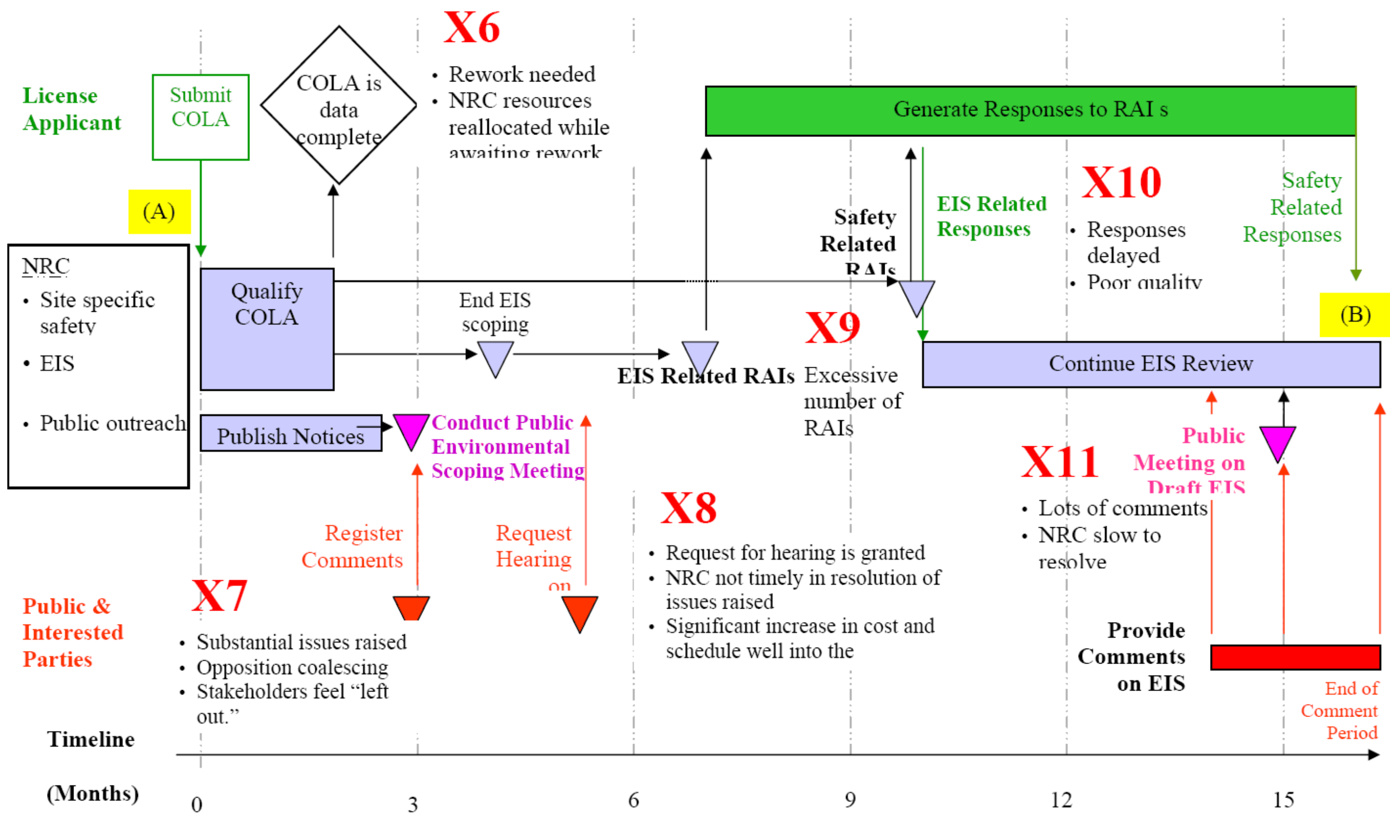

Figure 4C-3. Process Map for NRC’s Combined Operating License Proceeding Critical Xs for Six Sigma Analysis.

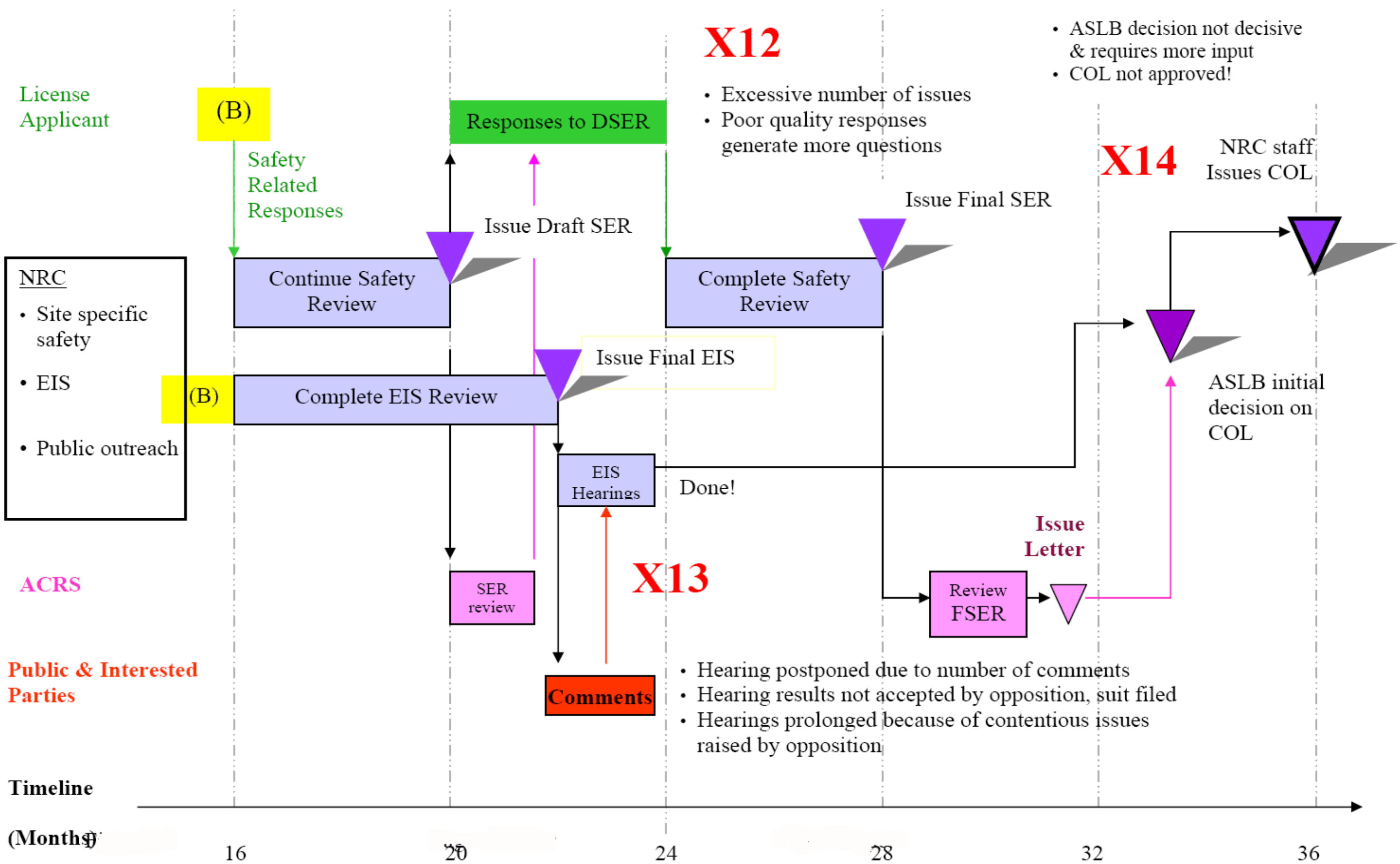

Figure 4C-4. Process Map for NRC's Combined Operating License Proceeding Critical Xs for Six Sigma Analysis.

Table 4C-1. Failure Mode Effects and Analysis

Process Step/Input	Potential Failure Modes	Potential Failure Defects	SEV	Potential Causes	Occurrence	Current Controls	DET	RPN	Action Recommended
What is the process step & input under investigation	In what way does the key variable go wrong?	What is the impact on the Key Output Variables (CTQs)?	How severe is the effect on the customer? 1-no impact 10-extreme impact	What causes the Key Input to go wrong?	How often does the cause or failure mode occur? 1-not likely 10-almost certain	What are the existing controls and procedures that prevent either the cause or the failure mode?	How well can you detect the cause or Failure Mode? 1-very likely to detect 10-very unlikely to detect	Priority	What are the actions for reducing the occurrence of the cause or improving detection?
	Project developer is not committed to construction	NRC resources may not be available	10	Concerned with reaction of Wall Street and shareholder	10	Develop a consortium that intends to build a plant at the outset.	10	**1000**	Form a Texas based consortium with intention to build a new plant. First construct a compelling prospective
	Site chosen is not pre-approved	Overall project and COL delay and more development capital needed	8	ESPs for available sites not pursued	10	Nothing can be done now except to choose a site with existing units	10	**800**	Seek involvement in consortium of potential site owners early on
X3	Doesn't add value	Adds to COL schedule and requires more upfront costs	8	Outdated NRC regulation	10	NEI and DOJ support eliminating this requirement for independent generators	10	**800**	Resurrect this issue with the NRC via NEI
	Design chosen requires significant licensing work	Overall project and COL delay	8	Licensed designs cost too much	5	Choose licensed designs if at all possible, encourage cost reductions	10	**400**	Ascertain if plants with Design Certifications are cost competitive. If not, are there actions that can be taken to change the economics?
X1	Improper scoping of COLA review	Potential for rework and schedule delay	5	Inexperience	10	NEI program seeking NRC guidance in 2005	5	**250**	Support NEI's COL Task Force

Table 4C-1. Failure Mode Effects and Analysis

Process Step/Input	Potential Failure Modes	Potential Failure Defects	SEV	Potential Causes	Occurrence	Current Controls	DET	RPN	Action Recommended
What is the process step & input under investigation	In what way does the key variable go wrong?	What is the impact on the Key Output Variables (CTQs)?	How severe is the effect on the customer? 1-no impact 10-extreme impact	What causes the Key Input to go wrong?	How often does the cause or failure mode occur? 1-not likely 10-almost certain	What are the existing controls and procedures that prevent either the cause or the failure mode?	How well can you detect the cause or Failure Mode? 1-very likely to detect 10-very unlikely to detect	Priority	What are the actions for reducing the occurrence of the cause or improving detection?
	Failure to submit as planned results in reallocation of NRC resources	Adds to schedule	10	Poor management of preparation efforts	5	Utilize management tools such as six sigma	5	**250**	Hire strong project manager and utilized proven tools
	New issues raised	Unexpected increase in overall schedule well into the project	10	Poor environmental work or poor outreach leading to attempts to stall review of EIS	5	Hire first class environmental firm and Budget time and money for extensive early outreach efforts	5	**250**	Identify and research potential firms to prepare and defend the EIS.
	Hearing results not accepted by stakeholders, file suit	Could be the end of the project if suit is not dismissed	10	Lack of consensus building with stakeholders	5	Budget time and money for extensive early outreach efforts	5	**250**	Develop strong community outreach program. Implement as soon as decision is made to proceed with COLA. Budget properly.
X14	ASLB decision has qualifications	Indefinite schedule delay	10	Poor management of COLA process by process by project developer	5	Place a full time licensing expert in Washington office	5	**250**	Identify and research firms with licensing (legal and eng.) Expertise that have strong Washington presence.
	COL denied	Disaster	10	Poor management of COLA process by project developer	5	Place a full time licensing expert in Washington office	5	**250**	Ditto

Table 4C-1. Failure Mode Effects and Analysis

Process Step/Input	Potential Failure Modes	Potential Failure Defects	SEV	Potential Causes	Occurrence	Current Controls	DET	RPN	Action Recommended
What is the process step & input under investigation	In what way does the key variable go wrong?	What is the impact on the Key Output Variables (CTQs)?	How severe is the effect on the customer? 1-no impact 10-extreme impact	What causes the Key Input to go wrong?	How often does the cause or failure mode occur? 1-not likely 10-almost certain	What are the existing controls and procedures that prevent either the cause or the failure mode?	How well can you detect the cause or Failure Mode? 1-very likely to detect 10-very unlikely to detect	Priority	What are the actions for reducing the occurrence of the cause or improving detection?
X4	Meeting generates negative reaction in the community	Adds to cost and schedule or forces developer to abandon the project	9	Fear or misunderstanding of project	5	Budget time and money for extensive early outreach efforts	5	**225**	Outreach program
X0	Unrealistic estimates of budget and schedule needed	Overall project and COL delay	10	Inexperience	7	Rely upon experienced legal and engineering firms	3	**210**	Hire first-class engineering, environmental, and law firms at outset to prepare estimates.
	Opposition coalescing	Could prolong schedule and force developer to abandon project	8	Lack of outreach by project developer	5	Budget time and money for extensive early outreach efforts	5	**200**	Outreach program
	Stakeholders feel “left out”	Could prolong schedule and force developer to abandon project	8	Lack information and interaction with project developer	5	Budget time and money for extensive early outreach efforts	5	**200**	Outreach program
	NRC is slow to resolve	Prolonged agony	8	Poor management by NRC or lack of information provided by environmental firm	5	Place a full time licensing expert in Washington office	5	**200**	Experts in Washington to closely follow proceedings

Table 4C-1. Failure Mode Effects and Analysis

Process Step/Input	Potential Failure Modes	Potential Failure Defects	SEV	Potential Causes	Occurrence	Current Controls	DET	RPN	Action Recommended
What is the process step & input under investigation	In what way does the key variable go wrong?	What is the impact on the Key Output Variables (CTQs)?	How severe is the effect on the customer? 1-no impact 10-extreme impact	What causes the Key Input to go wrong?	How often does the cause or failure mode occur? 1-not likely 10-almost certain	What are the existing controls and procedures that prevent either the cause or the failure mode?	How well can you detect the cause or Failure Mode? 1-very likely to detect 10-very unlikely to detect	Priority	What are the actions for reducing the occurrence of the cause or improving detection?
X13	Flood of comments	Hearing date postponed	9	Poor environmental work or poor outreach leading to attempts to stall review of EIS	7	Hire first class environmental firm and budget time and money for extensive early outreach efforts	3	**189**	
	Hearings prolonged because of contentious issues raised by opposition	Real or make believe issues raised	9	Ditto	7	Budget time and money for extensive early outreach efforts	3	**189**	
X2	Takes more than 6 months	Lengthens COL schedule	7	NRC not focused on this project	5	Submit COLA with announced intentions to build	5	**175**	
	Significantly exceeds budget		8	Failure to use industry efforts	3	Develop ties with NEI, NuStart, Dominion and TVA	7	**168**	

TASK 5 APPENDIX

APPENDIX 5A. ELECTRICITY COMPANIES PARTICIPATING IN OLKILUOTO 3

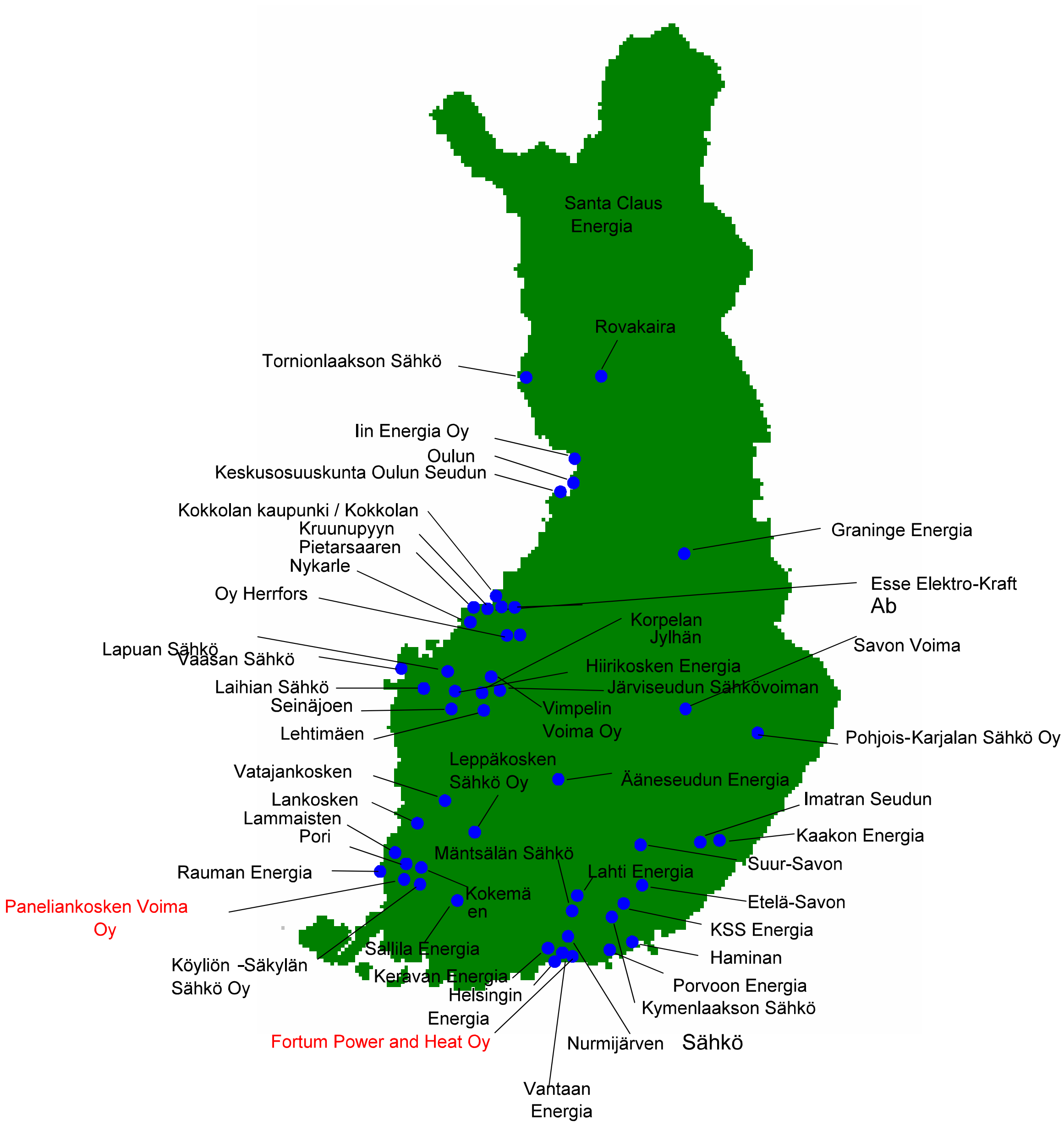

Figure 5A-1. Finnish Electricity Companies Participating in Olkiluoto 3

APPENDIX 5B. NRC FINANCIAL QUALIFICATIONS

5B-1. FINANCIAL QUALIFICATIONS ISSUE

Are there regulatory and policy bases for establishing by rulemaking a class of non-utility licensees who need not submit the financial qualifications information otherwise required by 10 CFR 50.33(f)?

Current Regulations

Section 182(a) of the Atomic Energy Act (AEA) requires license applications to include such information on the financial qualifications of the applicant as the Commission may specify by regulation. Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.33(f) specifies the information sufficient to demonstrate to the Commission the financial qualifications of the applicant. Electric utility applicants are not required to provide this information because the financial qualifications have been established for electric utilities on a generic basis by rulemaking. An electric utility is defined in 10 CFR 50.2 as "any entity that generates or distributes electricity and which recovers the cost of this electricity, either directly or indirectly, through rates established by the entity itself or by a separate regulatory authority." An application for a new facility may be submitted under either 10 CFR Part 50 or 10 CFR Part 52 of the regulations. In either case, a non-utility applicant is required to submit financial qualifications information as stated in 10 CFR 50.33(f).

Discussion

The NRC issued NUREG-1577, Rev. 1, "Standard Review Plan on Power Reactor Licensee Financial Qualifications and Decommissioning Funding Assurance" to describe the process it uses to review the applicant's financial qualifications and proposed methods of providing decommissioning funding assurance to evaluate compliance with the financial qualifications requirements of 10 CFR 50.33(f). Under these requirements, the NRC staff is obligated to conduct a financial qualifications review for each license application. If an applicant does not satisfy the definition of an electric utility, it is deemed to be a non-utility. Utilities use rate base rate of return, which provides a more stable and regular income. Non-utilities face more competition in the marketplace than utilities and are not guaranteed a return by a State public service commission. The financial information required to fulfill 10 CFR 50.33(f) is information that the applicant will have at its disposal. The NRC seeks to review financial information in order to have reasonable assurance that the facility will have the resources to operate safely. The staff believes it is premature to categorize any applicant as having reasonable assurance before examining such assets or parental guarantees.

Non-electric utility applicants 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, as required by Appendix C of Part 50. This submittal will be reviewed by the staff using the process provided in NUREG-1577, Rev. 1. At the March 27, 2002, public workshop, Greenpeace provided comments on this issue. They stated that "the public would be well served if the NRC would require the financial requirements be met and not exempt any merchant plant from that requirement."

Recommendation

The Commission has the authority to determine by regulation that a given class of non-electric utility applicants for nuclear power plant licenses shall not be required to submit financial qualifications information. However, the staff has not identified a reasonable basis for establishing such a class of applicants. The staff recommends that non-electric-utility applicants continue to be required to submit financial qualifications information in accordance with 10 CFR 50.33(f).

APPENDIX 5C. DECOMMISSIONING FUNDING ISSUE

5C-1. DECOMMISSIONING FUNDING ISSUE

Can a non-utility utilize an alternative method for decommissioning funding, such as partial prepayment?

Current Regulations

The regulations of 10 CFR 50.75 contain the requirements for providing decommissioning funding assurance. The regulations describe six methods of providing decommissioning funding assurance(1) prepayment, (2) an external sinking fund, (3) surety bonds, (4) a corporate parent guarantee, (5) contracts, and (6) any other mechanism or combination of mechanisms that is determined by the NRC to provide assurance of decommissioning funding. Utilities are licensees that are rate-regulated; they may use any of the six methods. Non-rate regulated licensees, such as merchant plant operators, may not use the sinking fund method, but are allowed to use any of the other methods. A non-utility may also use an external sinking fund in combination with a guarantee mechanism, provided that the total amount of funds estimated to be necessary for decommissioning is assured. The only notable exception to the above is a power reactor licensee that has the full faith and credit backing of the United States Government. This option entails a statement of intent containing a cost estimate for decommissioning and indicating that funds for the decommissioning will be obtained when necessary.

Discussion

The intent of this regulation is to provide assurance that decommissioning funding is available, particularly in the event of a permanent shutdown of the plant prior to the expiration of the license. According to the regulations, all funding options are available to a non-utility or a non-rate regulated entity except the sinking fund option. A sinking fund is a fund that is accumulated by making periodic deposits and is reserved for a specific purpose, such as retirement of debt or decommissioning of a commercial nuclear reactor. In a sinking fund, uniform periodic payments accumulate at compound interest to a given sum at a given future time. Exelon considered proposing an alternative decommissioning funding method for the PBMR that involved a partial payment of the total decommissioning cost estimate and annual contributions over the next 20 years. This proposed method of decommissioning funding is deemed a form of a sinking fund.

The staff does not believe that a sinking fund alone would provide the same level of assurance as other funding options available to non-rate-regulated entities and is not consistent with current requirements. Further, an exemption to use a sinking fund is likely to be difficult to justify technically since non-utilities do not have a rate base rate of return (i.e., a guaranteed rate base). However, as noted in the staff's position in item F, "Minimum Decommissioning Cost Estimates," a non-LWR applicant would be able to use an adequately justified site-specific estimate for decommissioning costs. Since the decommissioning cost estimate would be based on a site-specific study, the staff interprets 10 CFR 50.75(e)(1)(i) (the prepayment option) to allow an applicant to take the 2-percent real earnings credit for the whole period if necessary if the final decontamination schedule and the schedule of cash flows necessary to complete decommissioning is specifically outlined in a site-specific estimate. The present value of even a relatively large decommissioning cost, when discounted back at 2-percent real rate of return, should not be very large and should thus not require an onerous initial deposit. Staff Position According to current NRC regulations, an applicant has several options for funding decommissioning. Non-electric-utility applicants are not allowed to use the sinking fund option exclusively (uniform series of payments).

The staff recommends that the NRC require non-electric utility applicants to use the other options provided in 10 CFR 50.75 to fund decommissioning costs. The staff does not recommend that the regulations be modified to allow additional alternatives for decommissioning funding.

TASK 6 APPENDIX

APPENDIX 6A.THE ERCOT MARKET MODELING PROCESS

To project electric prices in the ERCOT market over the life of the proposed TGCN facility, we employed the Electric Power Market Model (EPMM).[1] It is a model of the electric industries of the U.S. and Canada and is divided into 34 interconnected electric markets and one of which is ERCOT. EPMM mimics a competitive electric market and projects energy and capacity prices for each of the 34 markets. Energy prices are projected by year, season and load period, and capacity prices are projected on an annual basis. In projecting electric prices, EPMM also projects, among other things (1) how existing facilities will be utilized, (2) where, when and what types of new capacity will be built to meet demand growth and how these facilities will be operated, (3) strategies for complying with environmental and other regulations. In making these projections, EPMM takes into account the ability to transmit power among the electric markets.

The data requirements include for each market: peak demand and energy forecasts, hourly variations in demand, existing mix of generating equipment, generating units under construction as well as generic options. For existing as well as new plants, EPMM takes into account their operating costs and characteristics. These include heat rate, nonfuel operating and maintenance costs, equivalent availability, forced outage rates, maintenance requirements, types of pollution control equipment and emission rates for various pollutants.

In addition, EPMM includes projections of prices for the fuels used in electric generating plants.

EPMM does not have fuels prices forecasting modules so it relies on assumptions about future fuel prices. Most important are the projections for natural gas prices for the 34 electric markets. Gas prices are particularly important in ERCOT since at the margin, electrics are determined by natural gas prices for about 60 percent of the hours in a year.

6A-1. NATURAL GAS FORECASTS

Texas electricity and natural gas prices over the period 1990 to 2004 are shown in Figure 6A-1, below.

As shown, natural gas prices have experienced significant volatility and in 2000 prices approached $10/MBtu before falling back to less than $2/MBtu in 2001. However, since most electric generators in Texas burning gas have contracts with gas suppliers that specify pricing, these spot prices do not translate into corresponding changes in electric prices. This is illustrated in Figure 6A-1 and shows that the volatility in electric prices is not as great as the volatility in natural gas prices. Whether or not this volatility in natural gas prices will continue into the future is unclear; but sustained high natural gas prices in ERCOT can have increasingly serious implications.

First of all high and sustained natural gas prices in ERCOT were unexpected and natural gas comprises about 72% of the total generation in ERCOT. What is even more important is that 25.4

1 The electric Power Market Model is software developed by the Economic and Management Consulting, LLC in Stony Brook, NY. EPMM is a structural model used for forecasting prices in power markets throughout the U.S. and Canada.

GW of natural gas capacity has entered the market since 1990, and 22.4 GW of this capacity has gone into commercial operation after 2000. Natural gas now sets the marginal electricity price in ERCOT about 60% of the time.

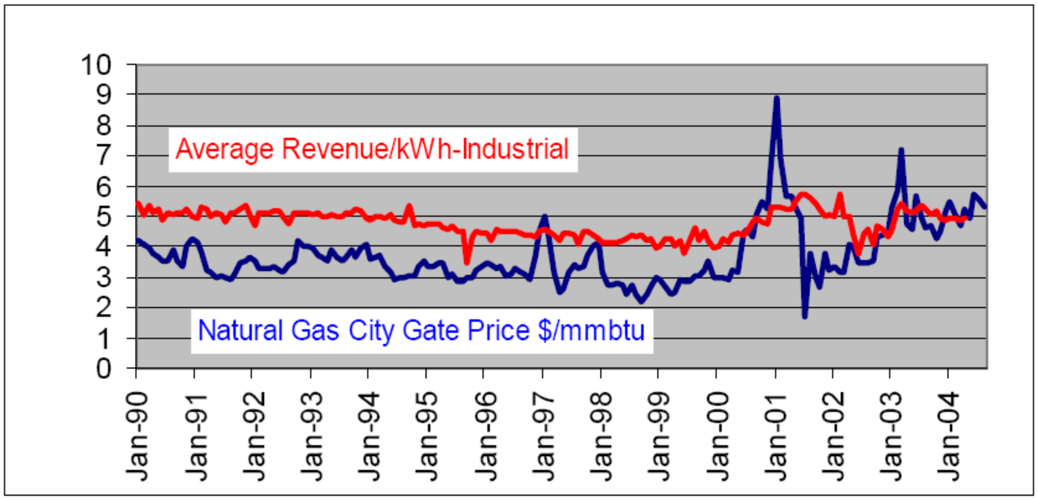

Figure 6A-1. Texas Electricity and Natural Gas Prices ($2002)
(Source: Modeling Texas Electric Price Variance; Geoff Rothwell, Stanford University,September, 2004, to be published)

Figure 6A-2 shows the predominant role of gas in ERCOT and emphasizes the need to give attention to gas price forecasting in EPMM.

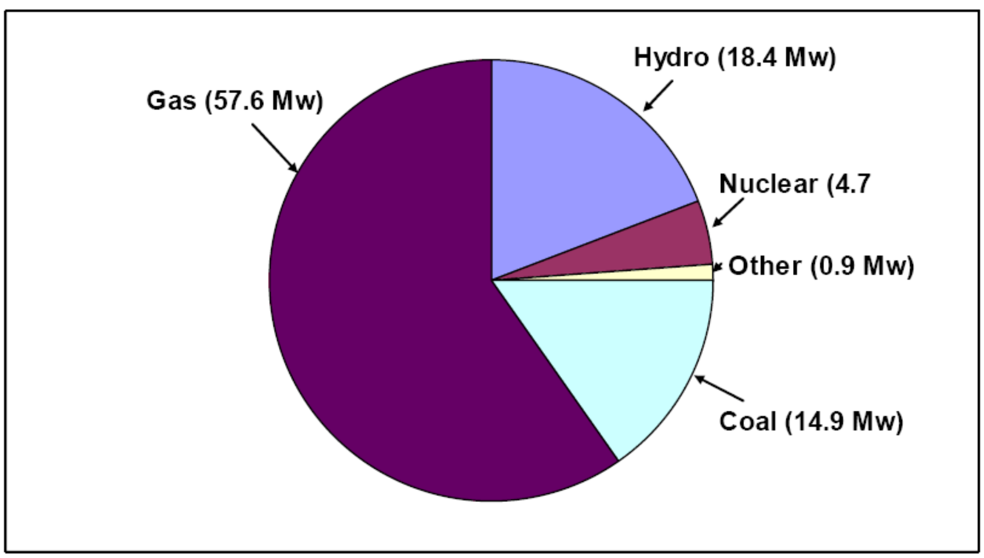

Figure 6A-2. Generation Technology in ERCOT *(Source: ERCOT)*

The approach that was taken in this analysis was to use for the Base Case the U.S. Department of Energy Annual Energy Outlook 2004 for wellhead natural gas price projections prepared by the Energy Information Administration.[2] However, a glance at Figure 6A-3 will show why there is disagreement over the direction of natural gas pricing.

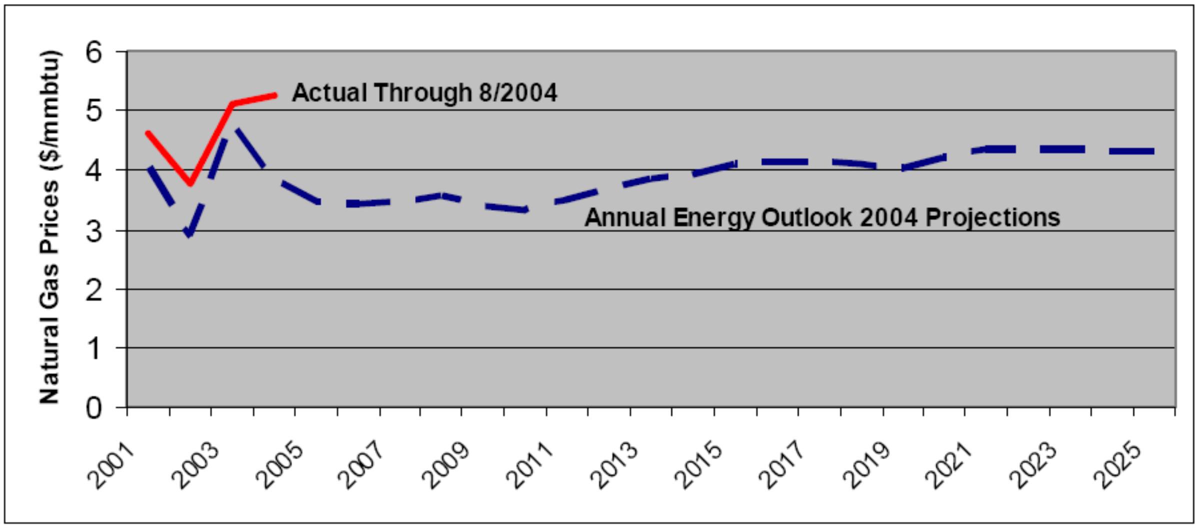

Figure 6A-3. Texas Actual and Forecasted Wellhead Natural Gas Prices from Annual Energy Outlook 2004 ($2002)
(Source: Annual Energy Outlook 2004 (EIA), DOE (Actual))

Current natural gas pricing levels appear to be tracking above the AEO forecast in the early months of 2004. And, although not shown on Figure 6A-3, as of late 2004, actual prices were remaining higher than forecast by the AEO. In any event, the AEO forecast goes through 2025 and the nuclear plant valuation projections require a forecast through at least 2040.[3]

We decided to keep the 2025 AEO natural gas price forecast at constant real levels through 2040 for the Base Case.

In addition to the Base Case, we evaluated two additional scenarios. First, we considered a higher gas price case. Second, we evaluated the impacts of a more stringent set of environmental regulations for the electric industry reflecting the Carper Bill that is now before the Congress.[4]

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2 The *Annual Energy Outlook* is an annual publication of the Energy Information Administration. It represents the DOE's view on the future of energy in the U.S. and is widely cited and referenced as the basis for pricing in energy studies. It can be accessed at http//www.eia.doe.gov/oiaf/aeo/index.html .

3 After approximately 20 years the discounting cash flows adds very little to the value of the plant.

4 The Carper Bill (S. 3135), introduced by Senator Thomas Carper (D-Del) is stringent environmental legislation which would tighten existing caps on utility emissions of SO_2 and introduce new caps on NOx, mercury and carbon dioxide (CO_2). The Bill is much more aggressive than President Bush's Clean Skies Initiative (CSI) in that it would require utilities to meet the legislation in less time; and CSI does not regulate CO_2.

A summary of the cases used in the Study are shown in Table 6A-1.

Table 6A-1. Summary of Cases Employed in Valuation Assessments

	Base Case	High Gas Case	Carper Case
Natural Gas Pricing	2010-2025 AEO ’04 (Figure 03) 2026-2040 2025 AEO ’04 prices held constant in constant 2002 dollars	2010-2025 Prices rise to $6.00/mmbtu in 2025 ($2002) 2026-2040 Price held at $6.00/mmbtu ($2002)	Same as Base Case
Alternative Fuels Pricing	Used AEO projections for alternate fuels	Same as Base Case	Same as Base Case
Environmental Legislation	Existing State and Federal Environmental Legislation maintained, including the 1990 Clean Air Act and its amendments	Same as Base Case	Carper Bill provisions enacted: more stringent limits on SO_2 and NO_x; introduces restraints on H_g and carbon emissions.
Electricity Demand	NERC projections for 2003-2008 (2.53% per year) used for entire period 2010-2040	Same as Base Case	Same as Base Case

The Carper Bill provisions are shown below in Table 6A-2, along with those for the Bush Clean Skies Act (CSA) and the 1990 Clean Air Act. It is immediately evident that the Carper provisions are considerably more demanding than the CSA.

Table 6A-2. Comparison of Current & Proposed Environmental Legislation *(Source: the Economic & Management Consulting LLC MACT=Maximum Available Control Technology)*

Regulation	Period	Sulfur Dioxide	Nitrogen Oxides	Mercury		Carbon
				Cap	MACT	
		1000 Tons		Tons	Lbs/kBtu	1000 Metric Tons
1990 Clean Air Act	from 2010	8,950	n/a	n/a	n/a	n/a
Clear Skies Act	2010-2017	4,500	1,474/715	34	n/a	n/a
	After 2017	3,000	1,474/715	15	n/a	
Carper Bill	2009-2012	4,500	1,870	24	4.0 or 50%	636,000
	2013-2015	3,500	1,700	10	2.4 or 70%	612,000
	After 2015	3,000	1,700	10	2.4 or 70%	612,000

These forecasts of natural gas pricing under the first two cases are shown graphically in Figure 6 A-4. The Carper Case uses the Base Case natural gas wellhead prices, but adds the emissions policy restrictions shown in Figure 6A-3.

Finally, the ERCOT electric price forecasts based on these assumptions are shown in Figure 6A-5.

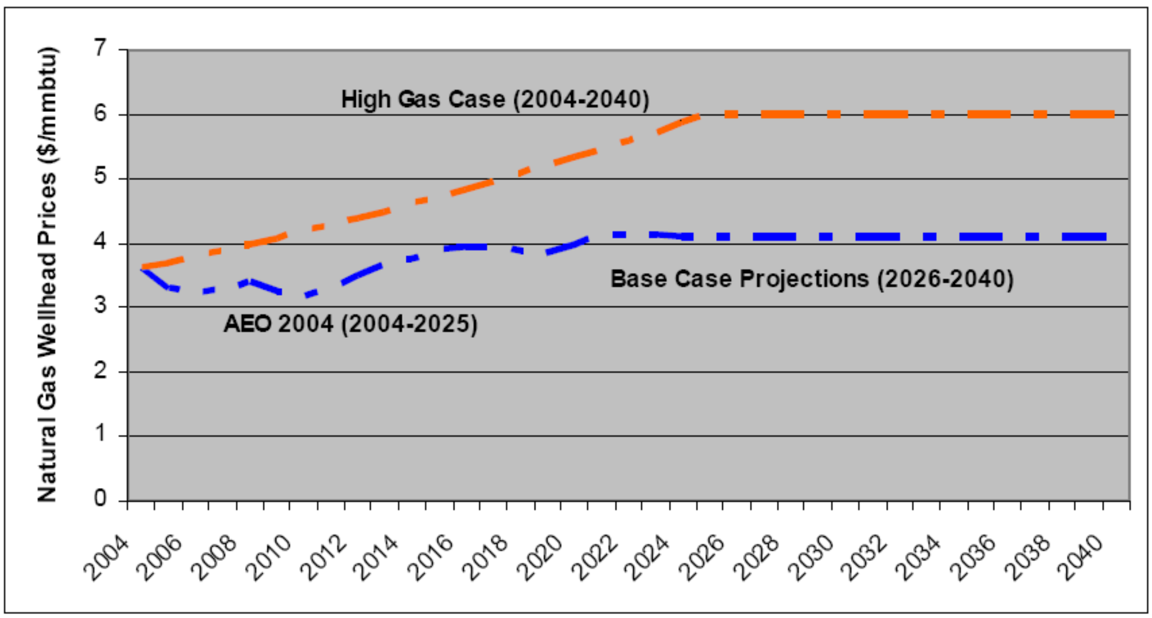

Figure 6A-4. Natural Gas Pricing Cases Used in the Study

The electric prices shown in Figure 6A-5 are long run equilibrium prices and appear relatively flat over the 2004-2030 time frame. After 2030 prices rise dramatically. The reason that the prices remain flat in the earlier time frame is because we have not restricted in any way the resource choices that exist under each price regime.[5]

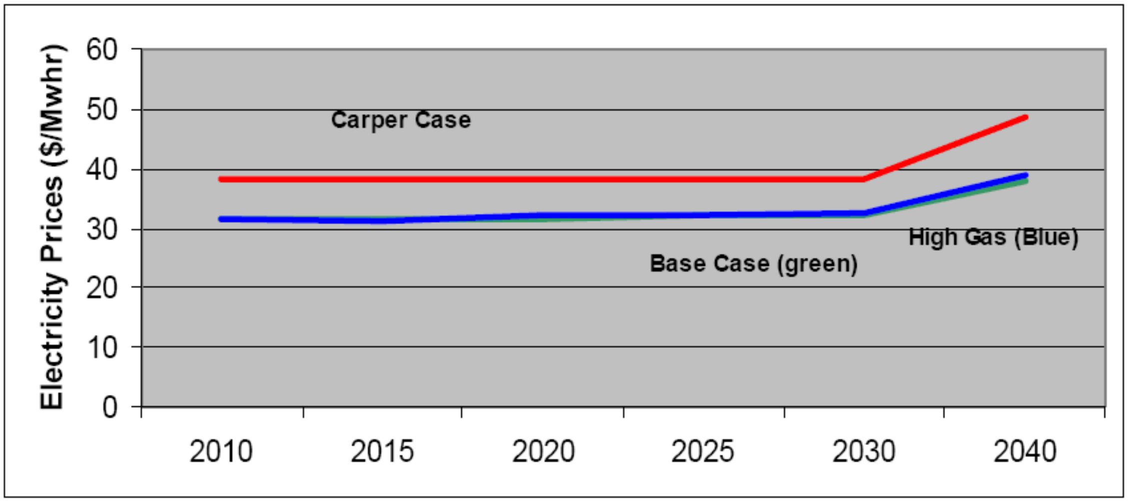

Figure 6A-5. Electricity Price Forecasts

For instance in the Base Case, there is a shift away from gas-burning advanced combined cycle units toward construction of new coal-fired capacity; almost 70,000 MWe of new coal units are constructed by 2040, as shown in Figure 6A-6. At the same time about 5,000 MWe of gas-fired capacity is built. This shift to coal-fired generation over the next 35 years reduces the upward pressure on electric prices. By comparison, if gas prices were to remain at around $3.50 million Btu through 2040, then approximately 36,000 MWe of new gas-fired capacity would be constructed, along with an additional 40,000 MWe of coal. All of this assumes that there are no restrictions that prohibit the introduction of new coal units in ERCOT.

5 In Figure 6A-5 the Base Case and the High Gas Case are difficult to individually discern as they are almost indentical.

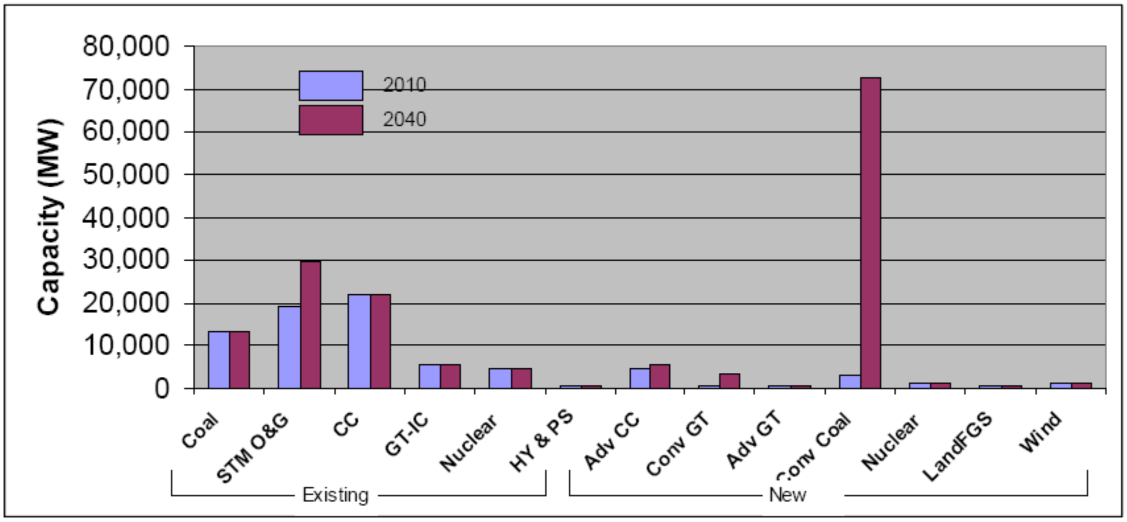

Figure 6A-6. ERCOT Resources In Base Case (2010 & 2040)

In the High Gas Price Case there is only 8,000 MWe of new gas-fired capacity and 73,000 MWe of coal. Thus, prices continue to moderate owing to the entrance of extensive coal capacity.

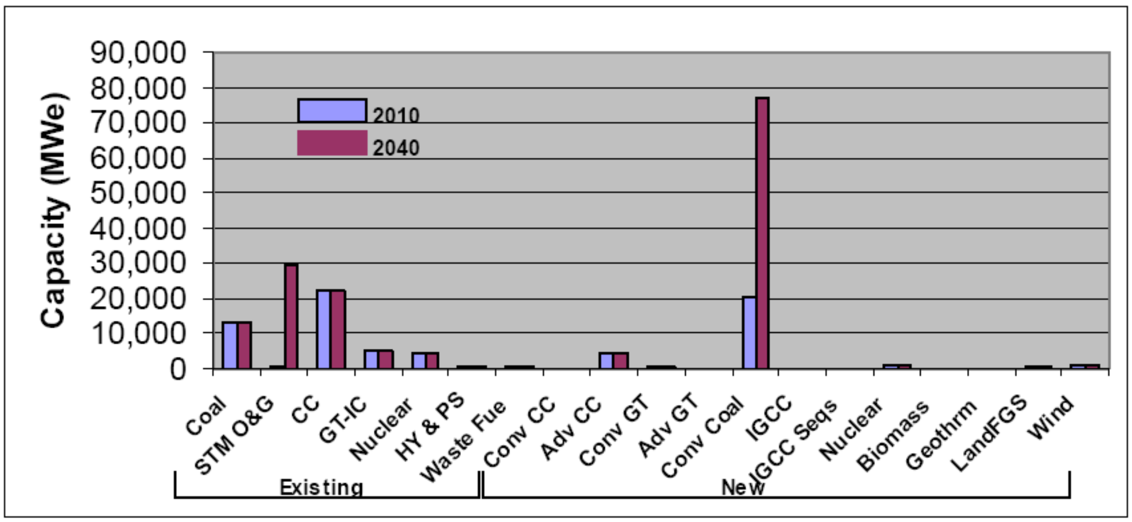

Figure 6A-7. ERCOT Resources in The High Gas Price Case (2010 & 2040)

Finally, under the Carper Case (Figure 6A-8), there would be a definite shift away from conventional coal units to, advanced gas plants, integrated gas combined cycle plant and renewables. New conventional coal units would comprise only 35,000 MWe-half of the new coal capacity in the previous two cases. Prices would be much higher than in the first two cases owing to the impact of more stringent restrictions on emissions of sulfur dioxide, nitrogen oxides and mercury as well as limiting emissions of carbon dioxide. Carbon allowance prices would progressively increase from about $14 per metric ton of carbon to $81 per metric ton by 2040 in constant 2002 dollars.

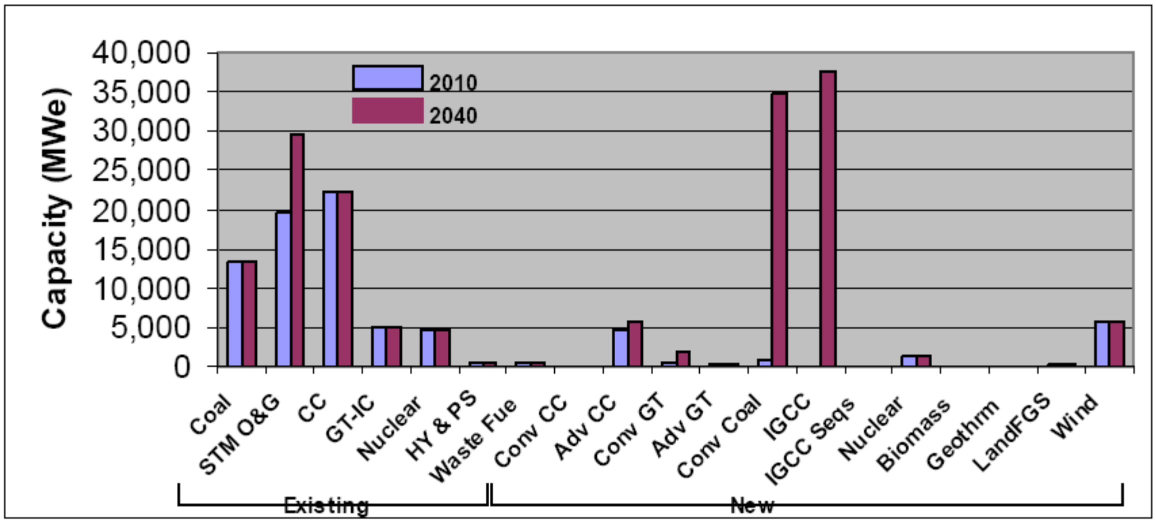

Figure 6A-8. ERCOT Resources in the Carper Case

Figure 6A-9 shows that were if new nuclear plants were not limited by EPMM, nuclear additions would account for most of the new additions in ERCOT under the Carper Case.

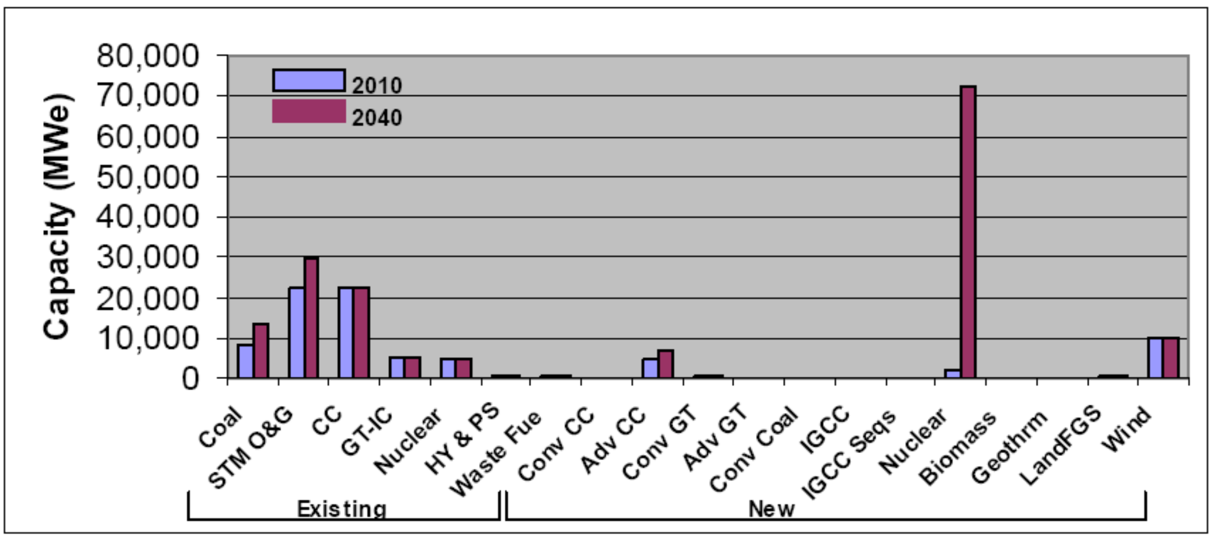

Figure 6A-9. ERCOT Resources in the Carper Case With Nuclear Unrestricted

APPENDIX 6B. THE ASSUMPTIONS USED IN THE RISK MODEL

The risk model is comprised of two software packages: *Value Analytix* accounting and valuation software and *Crystal Ball* risk simulation software.[6] Because *Crystal Ball* is an Excel add in, then an Excel model which mimicked *Value Analytix* was developed and benchmarked against Value Analytix. Further, continual benchmarking took place to insure that the accounting and valuations were being performed correctly.

This Appendix will deal with the assumptions used in the risk model.

6B-1. THE PRICE FORECAST

The risk model is used to forecast real option values. While the EPMM has provided three price forecasts corresponding to the three cases used in the Study, it is necessary to treat electric price as a random variable in the risk model. Thus, it needs to be modeled so that it can replicate the results of the three scenarios while still maintaining its stochasticity.

In order to do this the mean electric price forecast is the middle of the forecast spread between the base case and the Carper case. The high gas price case is nearly identical to the base case forecast and so is not used to weight the mean forecast. This is shown in Figure 6B-1 below

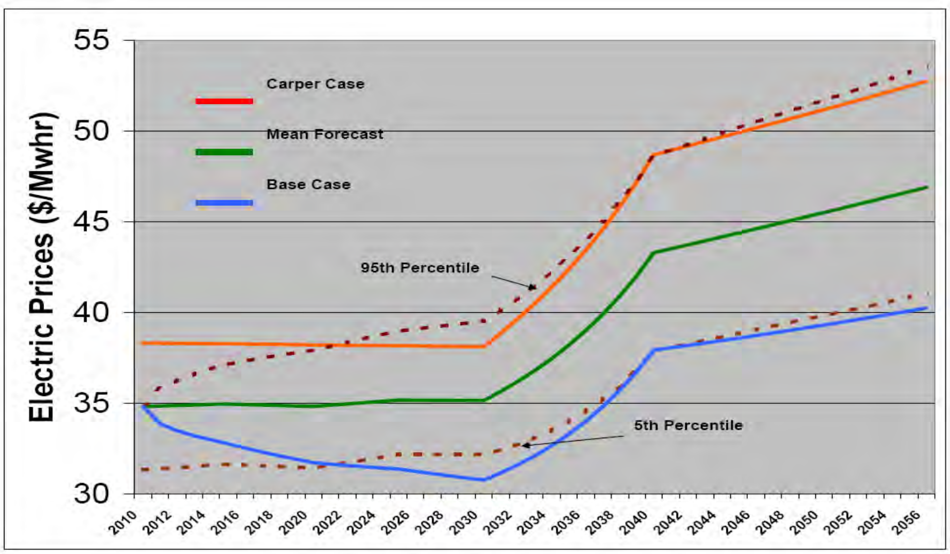

Figure 6B-1. Basis for the Mean Forecast Used in the Risk Model

Using Dr. Rothwell's analysis of electric price variance in ERCOT, it was determined that the 5th and 95th percentile (90% confidence interval) would be represented much like that used in

6 Value Analytix is a product of Value Analytix, Incorporated in London, England and is used to perform the cash flow assessments and the valuation of the nuclear project (www.valueanalytix.com) . Crystal Ball is a product of Decisioneering, Inc. in Denver, Colorado and is an Excel add-in which performs Monte Carlo simulations.(www.crystalball.com).

brownian motion with drift-as a bracket around the mean using 1.96 on both sides of the forecast mean.[7] The standard deviation used by Dr. Rothwell was based on the following model:

$$X_t = X_{t-1} + \sigma$$

where **O**$_t$ is the price of electricity in year ***t*** and **F** is the constant variance. In this study this model has been used in the modified form

$$X_t = \bar{X}_t + \sigma$$

where $\bar{X}_t$ is the mean forecast in year for ***t***

Thus the 90% confidence interval is determined by

$X'_t = \bar{X}_t \pm 1.96\sigma$ where X'_t is 5th and 95th percentile price

and as can be seen from Figure 6B-1 it fairly accurately brackets the Carper and base cases when using Dr. Rothwell's = 0.5. This price variable is then used in the Crystal Ball™ risk simulation software to simulate electric prices in ERCOT. A sample simulation is shown in Figure 6B-2, below.

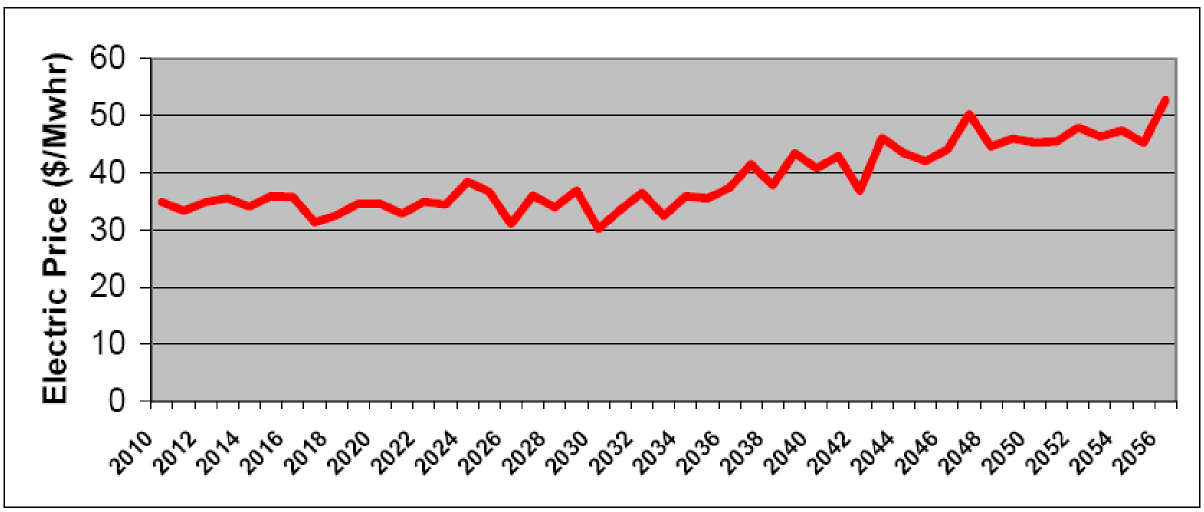

Figure 6B-2. Simulation of Electric Prices in ERCOT (2010-2056)

7 Rothwell, Geoffrey, Modeling Electric Price Variance, Stanford University, (Sept 2004) To be published.

6B-2. EPC COSTS

Following the guidance provided by Dr. Rothwell, EPC costs were modeled in the risk model as a lognormal distribution with the standard deviation equal to the supplier's stated contingency.[8]

We employed a representative plant by using averages from three different NSS suppliers. The mean of the EPC estimates was $1388/kWe and the combined standard deviation was 188 $/kWe.[9] Since it is very unlikely that any supplier would quote less than the current estimate of EPC costs, the lognormal distribution was truncated at $1388/kWe, and this is shown in Figure 6B-3, below. The truncation results in the mean being $1535/kWe.

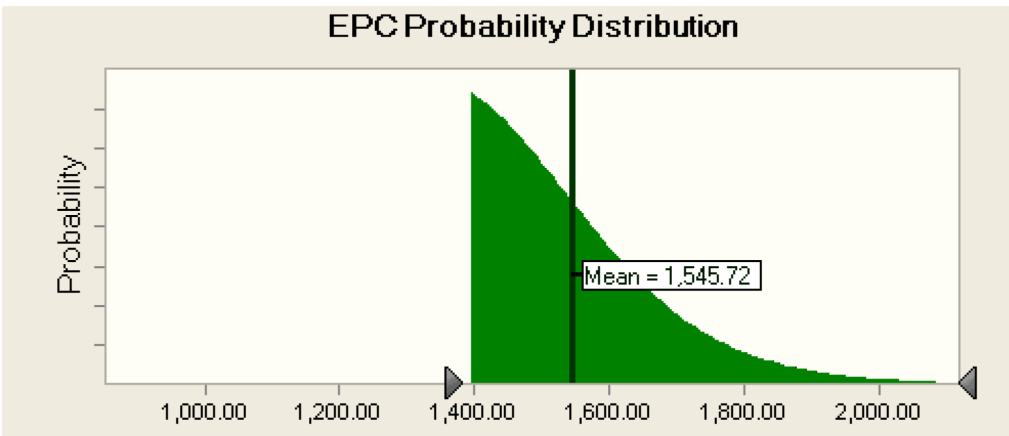

Figure 6B-3. The Probability Distribution for EPC Costs

6B-3. CONSTRUCTION SCHEDULE AND COSTS

The risk model, as designed, is not capable of altering the nuclear plant construction schedule easily. Yet this is a very important component of the risk model. Construction delays and overruns are a characteristic of the last round of nuclear construction and investors have long memories of the financial problems that emerged as plants were delayed, and as costs were greatly exceeded, not only because of the delays; but because the construction scope changed after construction had begun.

So, it was important to be able to model this uncertainty in the risk model.

This was accomplished by recognizing that the present value of a given increase in the cost of construction could be characterized as an equivalent EPC cost present value. So the schedule

8 Rothwell, Geoffrey, Cost Contingency as the Standard Deviation of the Cost Estimate, Stanford University Department of Economics, (May, 2004).

9 The suppliers used in the average wereGE ABWR, Westinghouse AP1000 and the AECL ACR 700. All of these suppliers provided confidential estimates of both the EPC costs and the contingencies which are to be used.

could remain the same as programmed into the risk model; but the loss in present value from a construction delay could be converted into an equivalent EPC cost present value.

To get an idea as to what the factor should be, it is easy to demonstrate that a $3 billion nuclear with a 5 year construction period, an IDC of 7% and a WACC of 7.5% will increase the present value of the plant investment by about 10% should a two year delay in plant startup occur. Thus the equivalent increase in EPC costs without a delay is about 10% .

The total present value of the plant investment can be made stochastic by modeling the EPC costs with a random variable that can take on values anywhere between 1 and 1.10.which is then multiplied by the random EPC costs (discussed above).Thus, the construction cost uncertainty is modeled in Crystal Ball with a uniform probability distribution as shown in Figure 6B-4.

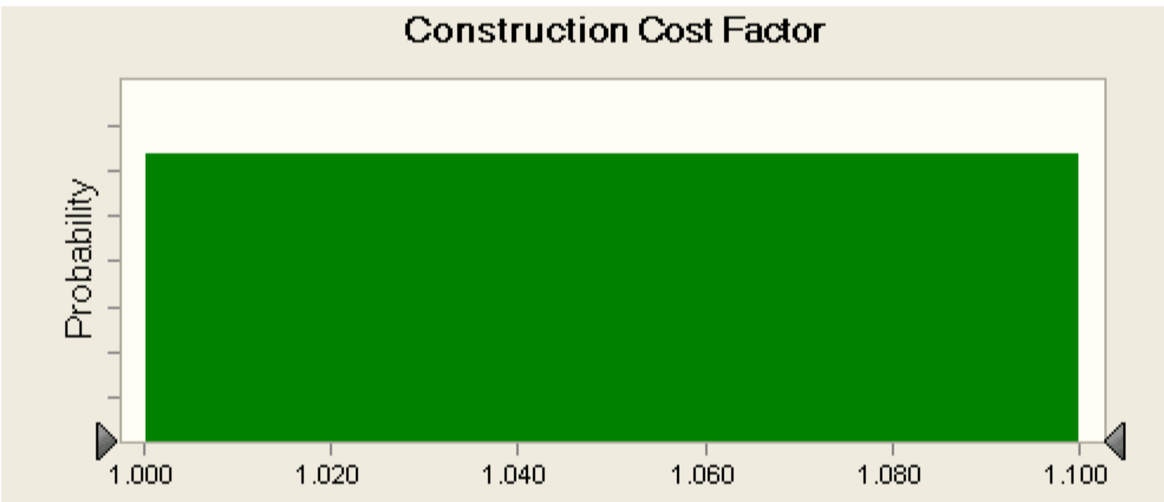

Figure 6B-4. Modeling Construction Schedule Uncertainty

The total constructed cost of the plant is then:

Total Plant Investment ($) = EPC Costs ($/kWe) X Capacity (kWe) X Construction Cost Factor

For the TGCN plant, the probability distribution of total plant investment is shown in Figure 6B-5 where no provision is made for a delay (construction cost factor =1) This should be compared to the same EPC forecast where the construction cost factor can uniformly take on values between 1.0 and 1.10 (Figure 6B-6). Compared to the no delay case in Figure B.4 construction delay noticeably shifts the EPC probability distribution to the right and increases the expected value of the distribution from $1550/kWe to $1620/kWe.

6B-4. PLANT PERFORMANCE UNCERTAINTIES

The TGCN plant is modeled as a top quartile performer. Thus, production costs are already modeled at a mean level of top quartile performers of about $70/kWe for O&M costs. Mean capacity factors are at 95% and are reduced to about 88% when outage refuelings take place.

To model uncertainties pertaining to both of these factors, we once again drew upon the work of Dr. Rothwell who has intensively studied the economics of nuclear power. In a paper published in Public Utilities Fortnightly (May, 2004) Dr. Rothwell modeled both production costs of U.S. nuclear plants as well as capacity factors.[10] The standard deviation of production cost is approximately 9% of the mean capacity factor, and production costs have a standard deviation of about 7% of mean capacity factor. These were the key statistics used in creating probability distributions for production costs and O&M.

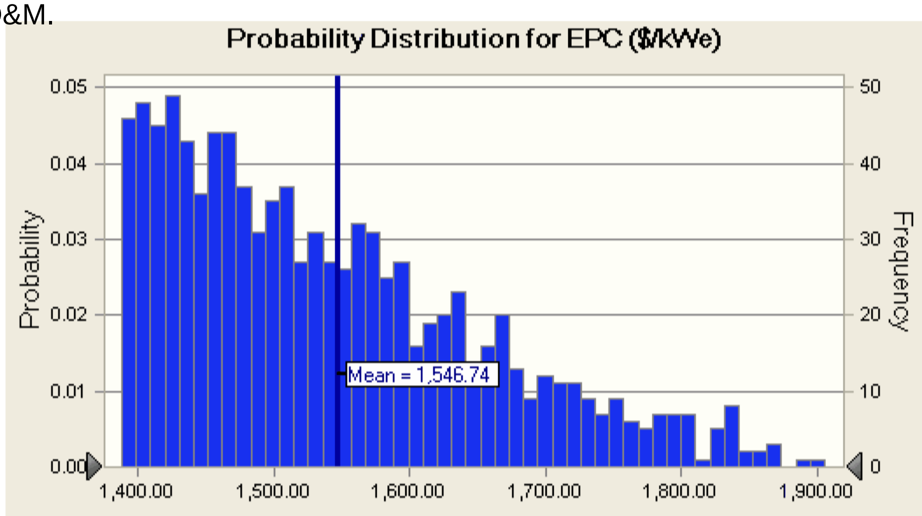

Figure 6B-5. Construction Cost Uncertainty Modeling (Construction Cost Factor =1)

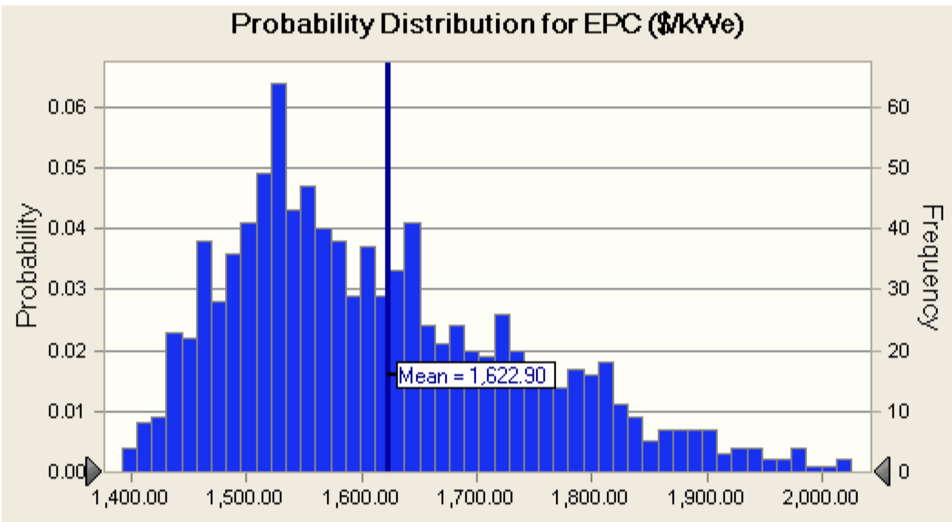

Figure 6B-6. Construction Cost Uncertainty Modeling (1<Construction Cost Factor<1.1)

10 Geoff Rothwell, Triggering Nuclear Development, Public Utilities Fortnightly, May 2004 pp47-51.

6B-4. COLA COST UNCERTAINTIES

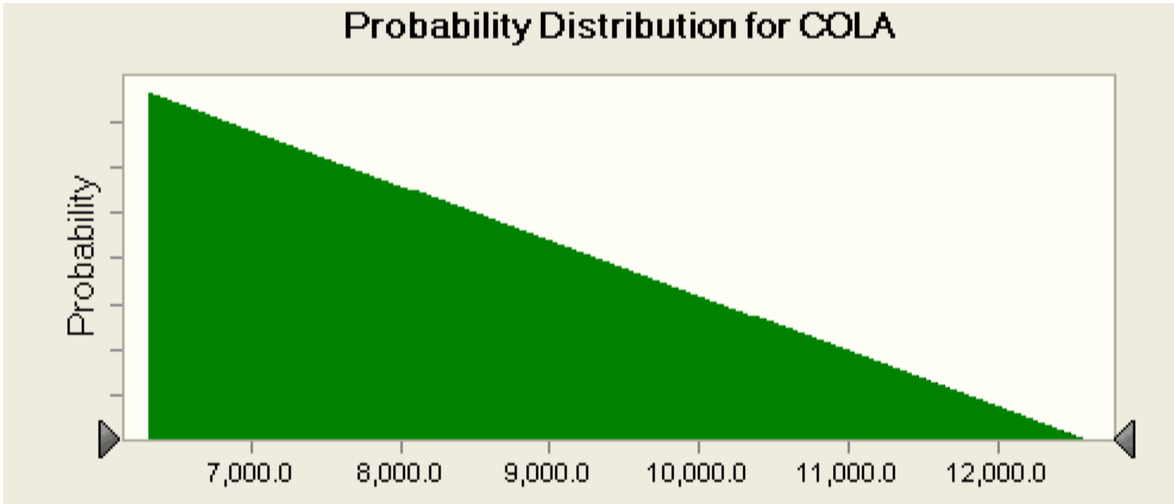

Figure 6B-7. Modeling COLA Uncertainty

The cost of obtaining a COL is estimated to be about $27 million. In order to recognize the uncertainty surrounding this estimate, the annual estimates of COL expenditures were permitted to double in any year with a triangular probability distribution such as that shown in Figure 6B-7, above. For the year shown in Figure 6B-7, the costs can range from about $6 million to over $12 million with the highest probability centered on $6 million with decreasing probability of greater amounts. The triangular probability distribution admits to slightly more knowledge than a uniform distribution.

APPENDIX 6C. REAL OPTIONS MODELING

6C-1.1. Real Options Modeling

Real options analysis is at least 20 years old; but has become more important over the last 10 years owing to the publication of two seminal books which enabled financial analysts and business economists to begin employing the theory in practice.[11] Its acceptance has been slow as the concept is difficult to conceptualize and the mathematics are quite complex for the average practitioner.

Nevertheless, much as financial options theory only slowly begin to see application after Myron Scholes and Fisher Black published their paper which solved the problem of how financial options are priced, there is now a growing consensus that real options exist and have value.[12] The problem is that the linkage between financial options and real options is not exact. This one fact has led to significant resistance to accept real options theory. Regardless, this obstacle is being overcome and it would not be a stretch to say that real options analysis is on the verge of being used by financial analysts more regularly.

What are real options?

A financial option gives its owner the right but not the obligation to purchase or sell an asset at a future date for a specified price. For instance, a call option is purchased on a stock by specifying when the option matures (must be exercised) and what price is to be paid for the stock on the exercise date. If the stock price is above the exercise price when the option expires, then the holder of the option can immediately realize a profit. If the stock price is lower than the exercise price, then the option holder would let the option expire. In this case the holder will not recover the price of the option.

The point here is that an option gives its owner the right to take action depending on the value of an underlying asset (in the example above the asset was a share of stock). The alternative would have been to buy the stock immediately and hope that it rose in value. If the stock were to drop in value, then the stockholder will have incurred losses. By buying the option, the only loss that can be incurred is the price of the option (which is always a fraction of the price of the stock). The asymmetry is what determines the value of the option.

This is shown schematically by Figure 6C-1.

The value of the option is shown on the vertical axis and the value of the stock is shown on the horizontal axis. When an option is purchased initially, the holder incurs a negative cash flow (the price of the option) shown as the option price on Figure 6C-1. Until the price of the stock reached

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11 Dixit, A.K.and Pindyck,R.S. 1994 *Investment Under Uncertainty*, Princeton University Press and Copeland, T and Antikarov, V. 2001 *Real OptionsA Practitioners Gude*, Texere.

12 Black, F. and Scholes, M. 1973 *The Pricing of Options and Corporate Liabilities*, Journal of Political Economy; 3, 639-654.

the exercise price (K) the holder will not exercise the option (since he will pay more for the stock than its current price). When the price of the stock exceeds C on the horizontal axis, then the option holder would exercise the option as the price of the stock exceeds the exercise price and recovers the option price as well. As the stock continues to increase, the option becomes more and more valuable, as shown on the vertical axis. For instance if the market price of the stock was A on the horizontal axis, then the value of the option would be A* on the vertical axis.

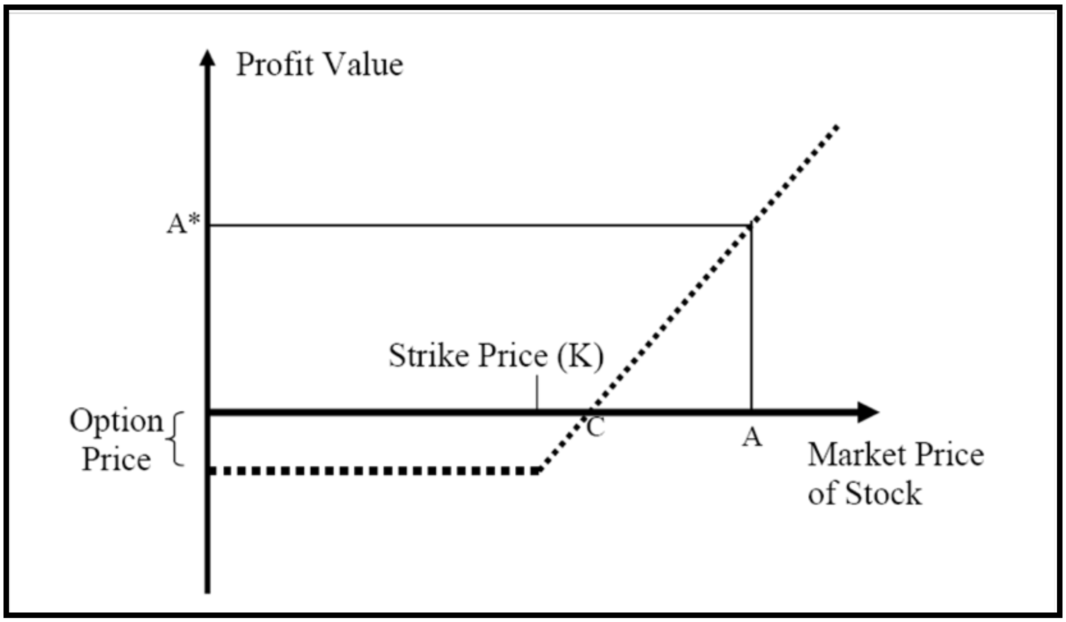


Figure 6C-1. How a Financial Option is Valued

A real option does exactly the same thing.

First of all, the TGCN plant now becomes the underlying asset instead of a share of stock, and the exercise price (K) becomes the cost of the investment (in present value). In other words when the TGCN plant reaches point C, then the option to construct the plant is exercised. This is shown in Figure 6C-2, below. In this case the dotted line is the net present value (NPV) of the nuclear plant.

But Figure 6C-2 is a static chart. It says that as long as the value of the plant is less than the construction costs and the COL then the plant is not constructed and no further costs should be expended. Suppose, however, that construction cannot happen for another three years because of all the lead activities to construction (e.g., securing financing, obtaining a COL, etc.). And further the present net present value of the plant is negative. Now what would be the proper course of action? The simple NPV rule would say not to invest (since NPV<0). However we have flexibility; we don’t have to invest now. We can wait and see what will happen to the value of the plant instead of saying that this investment should not happen.

How do we determine the value of the plant in the future? And, what is the likelihood that it will have a positive NPV when the time has come to make the construction decision. If the value of the plant is stochastic, then we can use probabilities (based on the plant's value volatility) to decide what the expected value of the plant might be.

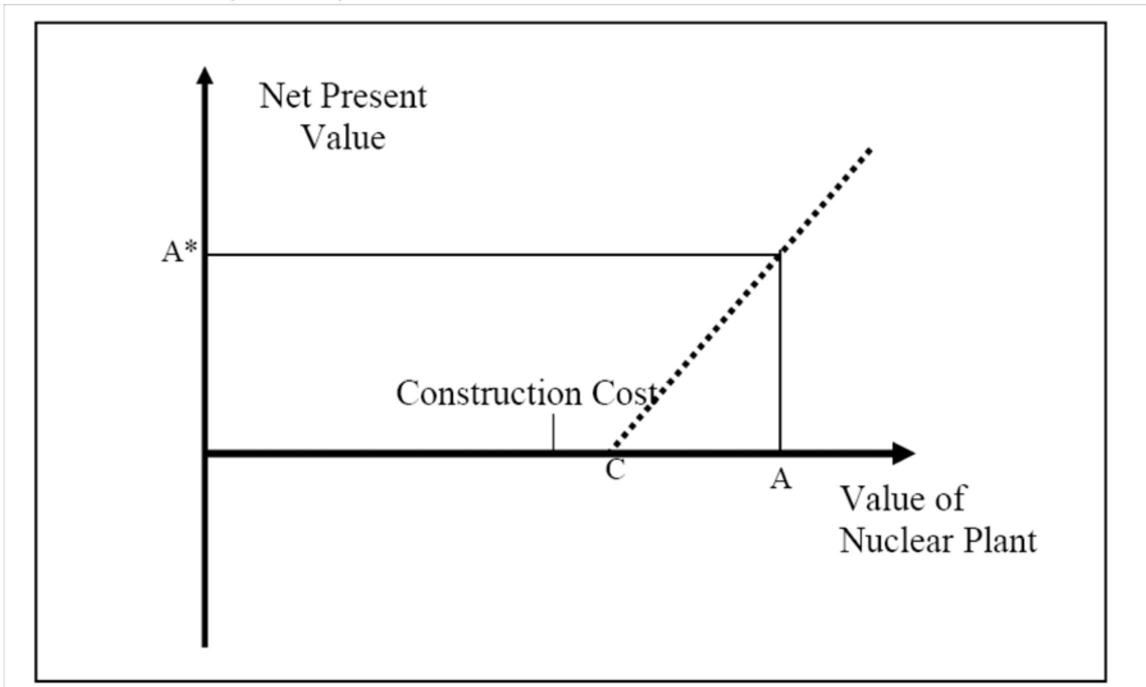


Figure 6C-2. The Real Options Framework

Real Option Value

The measure of how uncertain is the value of the plant in the future is the standard deviation sigma of the plant's value. In other words, the plant can take on values depending on such influences as the price of electricity, operating costs, operating performance, cost of capital, etc. As long as the standard deviation of the value of the plant gives some probability that the value will exceed the construction costs, then the option to build the plant has more value than its current NPV.

This is shown in Figure 6C-3.

Figure 6C-3 shows not only the NPV on the vertical axis; but also the option value (F). As is always the case the option value for sigmas are positive, indicating that the decision should be to wait as there is a strong enough probability that the value of the plant will exceed the investment costs when it's time to exercise the construction decision. And the higher is sigma, the greater is the option value, F. As the present value of the plant moves further to the right, then the option value decreases relative to the NPV, finally approaching the NPV when the present value of the plant is high enough. At that point, and assuming the NPV is positive, there is no value in waiting any longer. Investment should be undertaken immediately.

Perhaps even more important is the observation that when option value exceeds the NPV then the difference (in present value terms) can be spent during the wait leading up to the construction decision. This is possible because the decision to invest is that NPV must be greater than or equal to zero. Thus, funds up to the difference between the option value and the NPV can be expended. If the funding exceeds this then the NPV could very well be negative when the construction decision is made. In Figure 6C-3 the option values for each sigma is higher than the NPV, and they all converge as the present value of the plant increases. The higher the standard deviation, the higher is the option value relative to the NPV (the option premium is the difference between the option value and the NPV)

The real options investment rule differs from the investment rule from capital budgeting theory. Capital budgeting theory deals only with the present; either the investment should be made immediately or not at all. But this rule ignores the fact that there is no need to make the investment decision immediately. As long as there is time then an option exists.

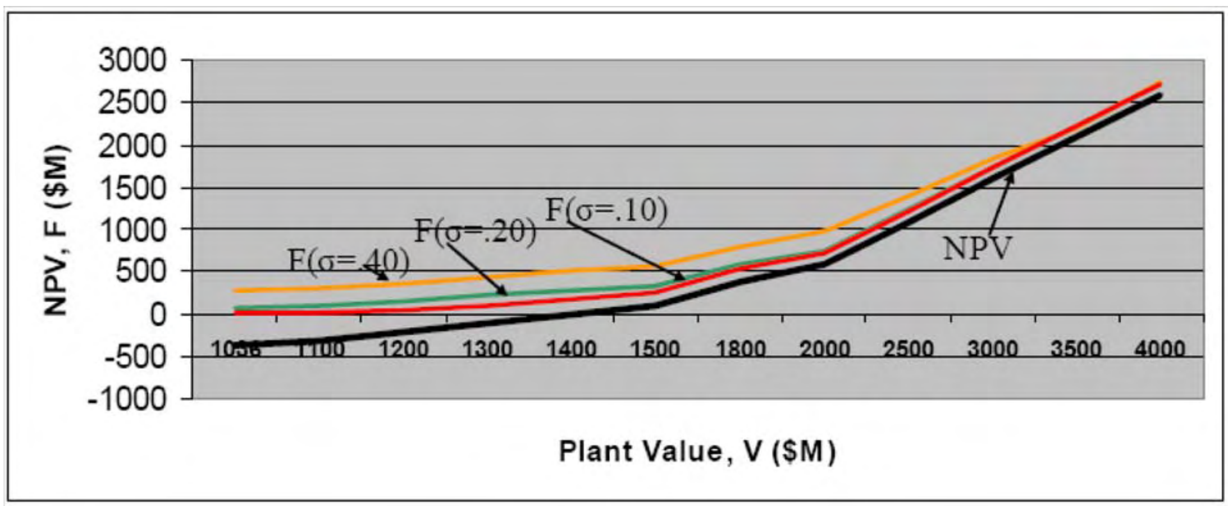


Figure 6C-3. The Option Value of the Nuclear Plant

Most of the mathematical intractability of real options surrounds the stochasticity of the underlying asset (in this case the nuclear plant).It is much more difficult to determine what the value of the plant is when you can't pick up the paper each day to see whether or not the option should be exercised or not. Or even sold to another buyer.

However, methods are slowly being developed to help practitioners uncover the options embedded in real assets. These methods were used in the Study to determine the option value of the plant and whether or not the investment should be made or not.

The process for performing a real options analysis is as follows:

1. Determine the existing NPV of the plant using standard valuation theory (i.e., discounting free cash flows)

2. Identify the key variables that determine the value of the plant, such as electric pricing, EPC costs, the cost of construction, etc.
3. Perform statistical assessments of each variable to identify its probability distribution, mean and standard deviation from historical data
4. Perform Monte Carlo simulation so that the standard deviation of the value of the plant can be determined as a combination of all the uncertainties (i.e., standard deviations) of the variables.
5. With the standard deviation of the plant known then there are several vehicles for determining what the option value is (and this is where the mathematical complexity arises). The most popular to practitioners is to either use the Black Scholes option pricing formula or develop a binomial option pricing lattice (see Copeland 2001). The latter was used in this Study.
6. The option value can be best understood as the value of the plant with the flexibility to not undertake investment if the NPV would be negative after the investment is made. Thus, it precludes all the outcomes that would result in a negative NPV while investing if the NPV would be positive. If the option value is higher than the NPV (see Figure 6C-3) then this would indicate that there is value in waiting to resolve uncertainties. When the option value and NPV are near equivalent then there is no longer any value in waiting and investment should follow immediately

One fallout of real options analysis is that the greater the uncertainty (i.e., higher standard deviation) the greater is the option value. Uncertainty gives rise to opportunity in the real options world.

APPENDIX 6D. THE NUCLEAR PLANT SCHEDULE AND NUCLEAR FUEL CYCLE

Figure 6D-1 shows the schedule used in Task 6 which initiates RFQ bids in February 2005 and goes into commercial operation in January 2015- a total period of 120 months. The actual construction period, beginning with site preparation and ending with commercial operation is about 54 months.

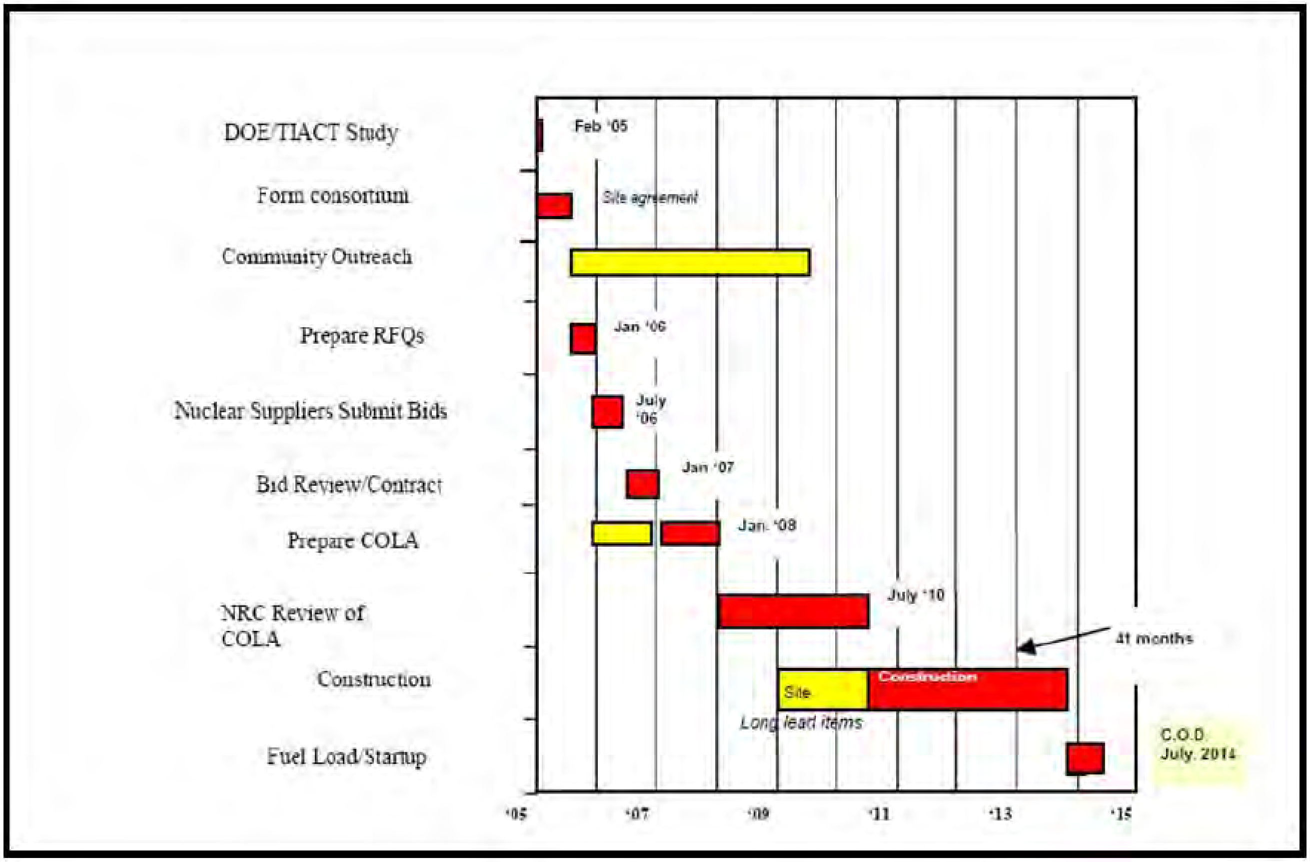


Figure 6D-1. The TGCN Plant Schedule

Table 6D-1 shows the nuclear fuel cycle of the TGCN plant. The nuclear fuel cycle data is shown in Table 6D-2 while Table 6D-3 shows the cost of nuclear fuel cycle components. These costs are kept constant throughout the Study (no real growth). Spent fuel is not shipped during the lifetime of the nuclear plant and decommissioning costs are set at $600 million in constant 2002 dollars. A decommissioning trust fund is established at $135 million at plant startup and it is allowed to accrue interest at 2% per year. At this juncture it is not known whether or not non-utility operated nuclear plant owners will be required to post a trust fund for decommissioning.

Table 6D-1. The Nuclear Fuel Cycle of the TGCN Plant

Fuel Cycle	Fuel Load	Testing	Startup	Shut	End Refuel	Uranium	Conversion	Enrichment	Fabrication
1	7/2/2014	10/1/2014	1/1/2015	12/31/2016	1/25/2017	7/2/2012	1/1/2013	7/2/2013	1/1/2014
2			1/25/2017	7/26/2018	8/20/2018	7/26/2016	1/25/2017	7/26/2017	1/25/2018
3			8/20/2018	2/19/2020	3/15/2020	2/19/2018	8/20/2018	2/19/2019	8/20/2019
4			3/15/2020	9/13/2021	10/8/2021	9/14/2019	3/15/2020	9/13/2020	3/15/2021
5			10/8/2021	4/9/2023	5/4/2023	4/9/2021	10/8/2021	4/9/2022	10/8/2022
6			5/4/2023	11/1/2024	11/26/2024	11/2/2022	5/4/2023	11/2/2023	5/3/2024
7			11/26/2024	5/28/2026	6/22/2026	5/28/2024	11/26/2024	5/28/2025	11/26/2025
8			6/22/2026	12/21/2027	1/15/2028	12/21/2025	6/22/2026	12/21/2026	6/22/2027
9			1/15/2028	7/16/2029	8/10/2029	7/17/2027	1/15/2028	7/16/2028	1/14/2029
10			8/10/2029	2/8/2031	3/5/2031	2/8/2029	8/10/2029	2/8/2030	8/10/2030
11			3/5/2031	9/3/2032	9/28/2032	9/4/2030	3/5/2031	9/4/2031	3/4/2032
12			9/28/2032	3/29/2034	4/23/2034	3/29/2032	9/28/2032	3/29/2033	9/28/2033
13			4/23/2034	10/23/2035	11/17/2035	10/23/2033	4/23/2034	10/23/2034	4/23/2035
14			11/17/2035	5/17/2037	6/11/2037	5/18/2035	11/17/2035	5/17/2036	11/16/2036
15			6/11/2037	12/11/2038	1/5/2039	12/11/2036	6/11/2037	12/11/2037	6/11/2038
16			1/5/2039	7/5/2040	7/30/2040	7/6/2038	1/5/2039	7/6/2039	1/5/2040
17			7/30/2040	1/29/2042	2/23/2042	1/30/2040	7/30/2040	1/29/2041	7/30/2041
18			2/23/2042	8/24/2043	9/18/2043	8/24/2041	2/23/2042	8/24/2042	2/23/2043
19			9/18/2043	3/19/2045	4/13/2045	3/20/2043	9/18/2043	3/19/2044	9/17/2044
20			4/13/2045	10/12/2046	11/6/2046	10/12/2044	4/13/2045	10/12/2045	4/13/2046
21			11/6/2046	5/7/2048	6/1/2048	5/8/2046	11/6/2046	5/8/2047	11/6/2047
22			6/1/2048	11/30/2049	12/25/2049	12/1/2047	6/1/2048	11/30/2048	6/1/2049
23			12/25/2049	6/26/2051	7/21/2051	6/26/2049	12/25/2049	6/26/2050	12/25/2050
24			7/21/2051	1/18/2053	2/12/2053	1/19/2051	7/21/2051	1/19/2052	7/20/2052
25			2/12/2053	8/14/2054	9/8/2054	8/14/2052	2/12/2053	8/14/2053	2/12/2054
26			9/8/2054	3/8/2056					

Table 6D-2. The TGCN Plant Fuel Cycle

Data	**Initial Core**	**Reload Core**
Fuel Cycle Length	24 months	18 months
Refueling Duration		25 days
Uranium to Fuel Load	30 months	24 months
Conversion to Fuel Load	24 months	18 months
Enrichment to Fuel Load	18 months	12 months
Fabrication to Fuel Load	12 months	6 months

Table 6D-3. The Cost of Nuclear Fuel Cycle Components (real 2002 dollars)

Data	Initial Core	Reload Core
Core Load	168 MTU	52.6 MTU
Uranium Cost (U308)	$19/lb	$19/lb
Conversion Cost (KgU)	$8/kg	$8/kg
Enrichment Cost (SWU)	$110/SWU	$119/SWU
Fabrication Cost (KgU)	$330/kg	$330/kg

APPENDIX 6E. INVESTOR CTQs

6E-1.1. INVESTOR CTQs

As discussed within Task 3, the end user CTQs (Critical to Quality evaluation factors) were developed as part of Task 1 as originally contemplated in the project plan. That plan included an assumption that a significant percentage of a perspective new plant would be owned by the end users. During the process of completing this research effort it was recognized that the viewpoints of investors would enhance the substance of the report. As a result, a new investor CTQ task activity was added to the report scope.

This activity included the selection of draft CTQs by the study team with validation by the investor community as part of this Task 6. This validation process included discussions with five financial industry professionals having backgrounds in corporate finance and investment banking.

This process resulted in selection of twelve investor focused CTQs which were subsequently applied as the basis for evaluation within several Tasks of this report project. These include Tasks 2-5.

Exactly like was done for end-users 'weighting factors' were developed for each of the CTQs. These are shown here in Table 6E-1. These weighting factors put a number from 1 to 10 on each of the CTQs where 10 is the highest weighting. These weighting factors are averaged over all five of the respondents.

Table 6E-1. Investor CTQs

CTQ Description	Weighting Factor
Certainty of COL & Construction Costs	10.0
Manage Nuclear Unique Risks	9.8
Public Acceptance	9.3
NRC Financial Policy for Nuclear Plants	9.2
Value Predictability	8.5
Waste Issue Resolution	8.5
Low Cost Return on Invested Capital (ROIC)	7.6
Debt/Equity Ratio	7.4
Cost Stability Bond Holder Investment Horizon	7.0
Minimum Development Cost	6.2
Long Power Purchase Agreement	5.0
Strong Customer Financials	5.0

A discussion of each CTQ follows providing more detailed definitions and background is shown in Table 6E-2.

Table 6E-2. CTQ Definitions

CTQ Description	Definition
Certainty of COL & Construction Costs	The potential for construction delays and subsequent increased IDC resulting from the delay.
Manage nuclear unique risks	The ability to manage risks that could result in increased and unplanned costs, such as unplanned and/or lengthy outages
Public acceptance	How important is it to investors to know that public acceptance supports plant and that interest/environmental groups cannot and will not interfere with the plant's construction or operation?
NRC financial policy for nuclear plants	How important to investors are financial provisions for nuclear liability insurance and sufficient funds to decommission the plant at the end of life?
Value predictability	Are financial projections conservative and believable?
Waste issue resolution	Where is the process going with regard to Yucca Mountain or another nuclear waste repository? How will the issues be resolved and on what timetable?
Low Cost Return on invested capital (ROIC)	How important are ROI measures relative to all other factors that equity investors may consider for investment in a nuclear plant?
Debt/Equity ratio	How important is it to equity investors to get highly leveraged financing (75/25 for example)?
Cost stability Bond holder investment horizon	How important to bondholders is getting principal and interest returned within a 10-20 year time horizon?
Minimum development cost	Can the costs of development up until the COL be kept to a minimum?
Long power purchase agreement	Can the plant get firm price and schedule commitments from consumers versus market price and demand
Strong customer financials	Is the counterparty to a PPA creditworthy?

APPENDIX 6F. CLASSIFICATION: NUCLEAR PLANT OPERATING PARAMETERS

This classification specifies key nuclear plant operational parameters which are used to determine any and all costs that are identified with the production of electricity, such as revenues, fuel burn and some variable costs.

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Net Rated Capacity (830.0.0)	1320 MWe	All periods	Supplier Information from Task 3	The nameplate rating of the plant in MWe. An average capacity rating of 1250 MWe was chosen as representative of the five plants: ▪ ABWR 1,440MWe ▪ AP1000 1,117MWe ▪ ACR700 2X703MWe
Retail Sales (MWhr) (820.0.0)	Calculated by model			The proportion of the plant's output that is committed to PPAs or retail sales to ultimate consumers. It is directly related to net rated capacity and capacity factor as: Sales (MWhr) =Net Rated Capacity (MWe) X Capacity factor (%) X hours in period

Classification: Nuclear Plant Operating Parameters (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Wholesale Sales (825.0.0	Calculated by model			The proportion of the plant's MWhr output that is sold in wholesale markets, typically for balancing purposes by the system operator in a bilateral market, and into the wholesale pool in pool-type markets. The calculation is the same as in retail markets (see above)

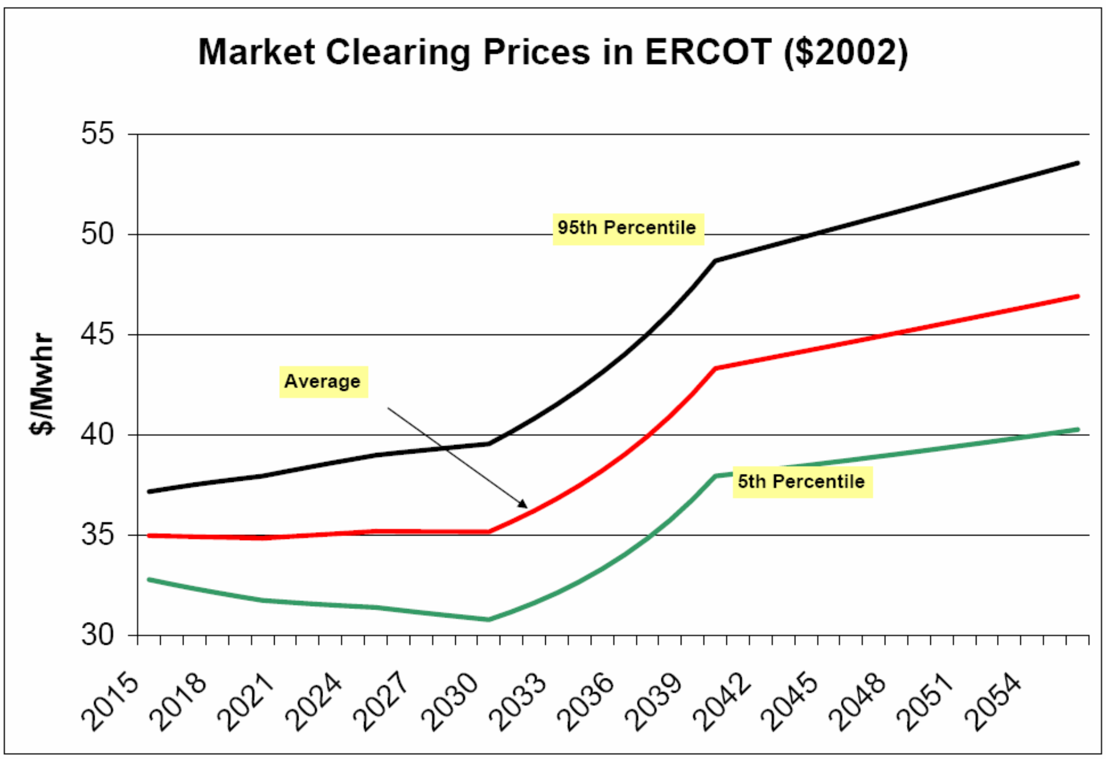
Classification: Nuclear Plant Operating Parameters (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Capacity Factor (840.0.0)	95.0	2015		The percentage of time that the nuclear plant is generating at rated power over the period Capacity factor is affected by unplanned outages, refueling outages, maintenance outages and plant deratings (or equipment deratings)... Refueling outages are assumed to be 25 days. The fuel cycle length is 18 months
	95.0	2016		
	88.2	2017		
	88.2	2018		
	95.0	2019		
	88.2	2020		
	88.2	2021		
	95.0	2022		
	88.2	2023		
	88.2	2024		
	95.0	2025		
	88.2	2026		
	92.4	2027		
	90.8	2028		
	88.2	2029		
	95.0	2030		
	88.2	2031		
	88.2	2032		
	95.0	2033		
	88.2	2034		
	88.2	2035		
	95.0	2036		
	88.2	2037		
	89.5	2038		
	93.6	2039		
	88.2	2040		
	95.0	2041		
	88.2	2042		
	88.2	2043		
	95.0	2044		
	88.2	2045		
	88.2	2046		
	95.0	2047		
	88.2	2048		
	88.2	2049		
	95.0	2050		
	88.2	2051		
	95.0	2052		
	88.2	2053		
	88.2	2054		
	95.0	2055		
	95.0	2056		

Classification: Revenue Accounts

These accounts calculate gross and net revenues from the nuclear power plant as electricity is sold into power markets.

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Retail Energy Price ($/MWhr) (800.0.0)	See Chart	2015-56	EPMM of *Economic & Management Consulting Inc. (Happaugue, NY)*	Market clearing price forecast in ERCOT. This price contains both the energy and the capacity price. The mean prices and the 5th and 95th percentile ranges are shown on the graph.



Classification: Revenue Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Revenues-retail ($) (1000.0.1)	Calculated by model			The model calculates revenues as: Price ($/MWhr) X (Generation (MWhr) in period)
Gross Tax Receipts (1020.0.0)	1.997%	All periods	Texas Statute Tax Codes *(http://www.capitol.state.tx.us/statutes/tx.toc.htm*)	A tax on revenues administered by State tax authorities.

Classification: Revenue Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Spent Fuel Waste Fee (1030.00.002)	10,993	2015	Nuclear Waste Policy Act of 1982 (NWPA) 42 U.S.C. 10101 et seq	The NWPA authorized that all generators of nuclear waste are to collect fees for the disposition of long lived high level waste including the permanent waste repository through revenues $.001/Mwhr (1 mil per kwhr) Data is in thousands of $2002.
	11,023	2016		
	10,201	2017		
	10,201	2018		
	10,993	2019		
	10,231	2020		
	10,201	2021		
	10,993	2022		
	10,201	2023		
	10,231	2024		
	10,993	2025		
	10,201	2026		
	10,692	2027		
	10,532	2028		
	10,201	2029		
	10,993	2030		
	10,201	2031		
	10,231	2032		
	10,993	2033		
	10,201	2034		
	10,201	2035		
	11,023	2036		
	10,201	2037		
	10,359	2038		
	10,835	2039		
	10,231	2040		
	10,993	2041		
	10,201	2042		
	10,201	2043		
	11,023	2044		
	10,201	2045		
	10,201	2046		
	10,993	2047		
	10,231	2048		
	10,201	2049		
	10,993	2050		
	10,201	2051		
	11,023	2052		
	10,201	2053		
	10,201	2054		
	10,993	2055		
	11,023	2056		

Classification: Production Cost Accounts

These are the accounts which comprise the costs of operating and maintaining the nuclear plant. Production costs comprise operation, maintenance and fuel expenses.

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Routine (non-outage) Staff Salaries, Benefits and Bonuses (1045.0.0)	\$59,836.6 \$60,000.0 \$11,229.5	2015 2016-55 2056-	(1)Suppliers confidential estimates from Task 3 (2) Dominion Study, Table 3-7 (3) Dominion Study, Table 4-12	The costs of on-site and off-site t labor charged to the nuclear plant. **Regular Salaries**: ▪ Site Staff \$38,368.4 ▪ Off-site Staff \$3,396 **Benefits:** ▪ Overtime 7.5% ▪ Retirement & benefits 38.5% ▪ Bonus & Incentives 8% ▪ Payroll tax 7.7% ▪ TOTAL BENEFIT MULTIPLER 1.617 (Study uses ABWR greenfield single site example and includes Security personnel)

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Fuel (1050.0.0)	61,047 61,214 56,645 56,645 61,047 56,812 56,645 61,047 56,645 56,812 61,047 56,645 59,374 58,485 56,645 61,047 56,645 56,812 61,047 57,020 57,020 61,589 57,020 57,900 61,666 58,312 62,547 58,145 58,145 62,714 58,145 58,145 62,547 58,312 58,145 62,547 58,145 62,714 58,145 58,145 62,547 62,714	2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056	*The Nuclear Fuel Cycle Calculator, (http://www.antenna.nl/wise/uranium/nfcc.html)*	This account amortizes the cost of nuclear fuel (see accounts 700.0.1 through 700.0.4) by assigning an amortization factor based on a unit of production (MWhr) method. Total Fuel Costs: $2,538,250 Total Generation 318,133,788 MWhr Amortization Factor: Costs/Generation = 5.55 $/MWhr Units are thousands of dollars

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Refueling Outage Costs- Outage Material (1055.0.1)	0.0 0 3,322 3,322 0 3,322 3,322 0 3,322 3,322 0 3,322 1,262 2,059 3,322 0 3,322 3,322 0 3,322 3,322 0 3,322 2,657 664 3,322 0 3,322 3,322 0 3,322 3,322 0 3,322 3,322 0 3,322 0 3,322 3,322 0 0	2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056	Dominion Study table 3-8 *Outage Cost Estimates (ABWR)*	The cost of incremental material used in an outage. This can be lubricants, coolants and water, chemicals, disposal rags, charts. Logs, health monitoring, decontamination supplies, tools, packing, gaskets, hoses, generator and exciter brushes, ink, protection equipment, first aid suppliers, lamps, report forms, building service supplies, etc. **The plant is on 18 month fuel cycles and 25 day outages.** **Data is in thousands of dollars**

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Refueling Outages- Refueling Costs (1055.0.2)	0.0 0 2,500 2,500 0 2,500 2,500 0 2,500 2,500 0 2,500 950 1,550 2,500 0 2,500 2,500 0 2,500 2,500 0 2,500 2,000 500 2,500 0 2,500 2,500 0 2,500 2,500 0 2,500 2,500 0 2,500 0 2,500 2,500 0 0	2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056	Dominion Study table 3-8 *Outage Cost Estimates (ABWR)*	This is the additional labor and contractor cost incurred in directly handling the nuclear fuel during an outage. Estimated to be $2500 per outage for the best current plants.

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Refueling Outages-Labor and Services (1055.0.3)	0.0	2015	Dominion Study table 3-8 *Outage Cost Estimates (ABWR)*	This the refueling cost associated with craft labor and contractor services not directly involved with moving fuel during the outage. This would include equipment servicing, control blade replacement, pipe and vessel inspections, equipment replacements and additions, steam generator inspections (PWRs only), turbine-generator inspections, welding, motor and valve inspections, etc. Estimated at $5,200,000 for the best plants.
	0	2016		
	5,200	2017		
	5,200	2018		
	0	2019		
	5,200	2020		
	5,200	2021		
	0	2022		
	5,200	2023		
	5,200	2024		
	0	2025		
	5,200	2026		
	1,976	2027		
	3,224	2028		
	5,200	2029		
	0	2030		
	5,200	2031		
	5,200	2032		
	0	2033		
	5,200	2034		
	5,200	2035		
	0	2036		
	5,200	2037		
	4,160	2038		
	1,040	2039		
	5,200	2040		
	0	2041		
	5,200	2042		
	5,200	2043		
	0	2044		
	5,200	2045		
	5,200	2046		
	0	2047		
	5,200	2048		
	5,200	2049		
	0	2050		
	5,200	2051		
	0	2052		
	5,200	2053		
	5,200	2054		
	0	2055		
	0	2056		

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Offsite Power During Outage (1055.0.4)	0.0 0 91 91 0 91 91 0 91 91 0 91 34 56 91 0 91 91 0 91 91 0 91 73 18 91 0 91 91 0 91 91 0 91 91 0 91 0 91 91 0 0	2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056	Dominion Study table 3-8 *Outage Cost Estimates (ABWR)*	This is the cost of offsite power per outage Based on $35/MWhr for 4 MWe consumption and 90% of total outage time.

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Materials, Supplies, Services and Upgrades (1060.0.0)	14,958.9 15,000 2,807	2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056	Dominion Study Table 3-7 and Table 4-12	The allowance for materials, supplies and equipment service and upgrades, normally performed by contractors. This is an estimate based on history

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
NRC Users Fees (1065.0.1)	3,438.6 3,448 645	2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056	10CFR171.15 (*NRC Regulations, Title 10 Code of Federal Regulations*)	A fee collected by the Nuclear Regulatory Commission to fund its power reactor safety and safeguards regulation & reactor decommissioning research. For FY2004 the fees are as follows: ▪ Operating Power Reactors $3,283,000 ▪ Power reactors in decomm with spent fuel on site $203,000 ▪ A surcharge for operating power reactors $165,000 ▪ A surcharge of power reactors in decomm with spent fuel $7,800 The fee is collected in the 3rd quarter of each year.

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
FEMA and Emergency Preparedness (1065.0.3)	546.3	2015	(1)44CFR354 *Title 44, Code of Federal Regulations, Part 354* (2) Dominion Study, Table 4-3 *DECCAR Model Inputs*	FEMA fees to recover their activities related to offsite radiological emergency planning and preparedness
	548	2016		
	548	2017		
	548	2018		
	548	2019		
	548	2020		
	548	2021		
	548	2022		
	548	2023		
	548	2024		
	548	2025		
	548	2026		
	548	2027		
	548	2028		
	548	2029		
	548	2030		
	548	2031		
	548	2032		
	548	2033		
	548	2034		
	548	2035		
	548	2036		
	548	2037		
	548	2038		
	548	2039		
	548	2040		
	548	2041		
	548	2042		
	548	2043		
	548	2044		
	548	2045		
	548	2046		
	548	2047		
	548	2048		
	548	2049		
	548	2050		
	548	2051		
	548	2052		
	548	2053		
	548	2054		
	548	2055		
	103	2056		

Classification: Production Cost Accounts (cont'd

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
NEI Fee (1065.0.2)	342.0 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 343 64	2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056	Dominion Study Table 3-7 *O&M Cost Calculation*	Membership fee for power reactor owners **Fee**: **$251.51 per gross MWe** If the nuclear plant gross is 1350 MWe then the fee is $339.5K

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
INPO (1065.0.3)	706.3	2015	Dominion Study, Table 3-7 *O&M Cost Calculations*	Membership fee for power reactor owners to INPO **Fee: $529,758 per site plus $176,586 per** unit **Total: $706.3K**
	706	2016		
	706	2017		
	706	2018		
	706	2019		
	706	2020		
	706	2021		
	706	2022		
	706	2023		
	706	2024		
	706	2025		
	706	2026		
	706	2027		
	706	2028		
	706	2029		
	706	2030		
	706	2031		
	706	2032		
	706	2033		
	706	2034		
	706	2035		
	706	2036		
	706	2037		
	706	2038		
	706	2039		
	706	2040		
	706	2041		
	706	2042		
	706	2043		
	706	2044		
	706	2045		
	706	2046		
	706	2047		
	706	2048		
	706	2049		
	706	2050		
	706	2051		
	706	2052		
	706	2053		
	706	2054		
	706	2055		
	132	2056		

Classification: Production Cost Accounts (cont'd

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Other Fees (1065.0.4)	2,991.8	2015	Dominion Study, Table 3-7 *O&M Cost Calculations*	Other fees for State emergency planning and all other contingencies **Fee: $3,000K**
	3,000	2016		
	3,000	2017		
	3,000	2018		
	3,000	2019		
	3,000	2020		
	3,000	2021		
	3,000	2022		
	3,000	2023		
	3,000	2024		
	3,000	2025		
	3,000	2026		
	3,000	2027		
	3,000	2028		
	3,000	2029		
	3,000	2030		
	3,000	2031		
	3,000	2032		
	3,000	2033		
	3,000	2034		
	3,000	2035		
	3,000	2036		
	3,000	2037		
	3,000	2038		
	3,000	2039		
	3,000	2040		
	3,000	2041		
	3,000	2042		
	3,000	2043		
	3,000	2044		
	3,000	2045		
	3,000	2046		
	3,000	2047		
	3,000	2048		
	3,000	2049		
	3,000	2050		
	3,000	2051		
	3,000	2052		
	3,000	2053		
	3,000	2054		
	3,000	2055		
	561	2056		

Classification: Production Cost Accounts (cont'd

Property & ad Valorem taxes (Operations) (1070.0.1)	18,761.8 18,813 3,521	2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 2046 2047 2048 2049 2050 2051 2052 2053 2054 2055 2056	*Taxing Metropolis: Tax Capacity and Tax Effort in Large U.S. Cities Table A4 (http://www.ibo.nyc.ny.us/iboreports/taxcapacity215.pdf)*	$3.09 for every $100 of fair market value while plant is in operation (.0309%) Includes property taxes for city (.72), County (.81), School (1.44) and Other (0.12). **Total is $3.09 per $100**

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Local Income Tax (1200.0.3)	.18%	All periods	*Taxing Metropolis: Tax Capacity and Tax Effort in Large U.S. Cities Table A4 (http://www.ibo.nyc.ny.us/iboreports/taxcapacity215.pdf)*	Business income in Houston is taxed at a rate of $0.18 per $100 of taxable income .(18%)

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Primary Insurance (1072.0.1)	5,185.8	2015	*(1)Price Anderson Act of 1957* & subsequent revisions (2) Dominion Study Table 3-7 *O&M Cost Calculations* (3) Dominion Study Table 4-2 *ABWR DECON Decommissioning Cost Estimate*	Premiums for primary liability insurance required under provisions of Price Anderson Act. This provides for $300 million of primary liability insurance. The premium is paid to American Nuclear Insurers-a pooled insurance organization. Currently the premium is $5.2M for a greenfield site and $1.5M for an additional unit at an existing site.
	5,200	2016		
	5,200	2017		
	5,200	2018		
	5,200	2019		
	5,200	2020		
	5,200	2021		
	5,200	2022		
	5,200	2023		
	5,200	2024		
	5,200	2025		
	5,200	2026		
	5,200	2027		
	5,200	2028		
	5,200	2029		
	5,200	2030		
	5,200	2031		
	5,200	2032		
	5,200	2033		
	5,200	2034		
	5,200	2035		
	5,200	2036		
	5,200	2037		
	5,200	2038		
	5,200	2039		
	5,200	2040		
	5,200	2041		
	5,200	2042		
	5,200	2043		
	5,200	2044		
	5,200	2045		
	5,200	2046		
	5,200	2047		
	5,200	2048		
	5,200	2049		
	5,200	2050		
	5,200	2051		
	5,200	2052		
	5,200	2053		
	5,200	2054		
	5,200	2055		
	973	2056		

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
NRC Indemnification Fees (1072.0.2)	37.4	2015	50CFR140.7 Part 50 Code of Federal Regulations, *Financial Protection Requirements*	NRC fees to administer the Price Anderson Act and to monitor special nuclear occurrences. **The fee for power reactors is $30 annually per thousand kilowatts capacity**
	38	2016		
	38	2017		
	38	2018		
	38	2019		
	38	2020		
	38	2021		
	38	2022		
	38	2023		
	38	2024		
	38	2025		
	38	2026		
	38	2027		
	38	2028		
	38	2029		
	38	2030		
	38	2031		
	38	2032		
	38	2033		
	38	2034		
	38	2035		
	38	2036		
	38	2037		
	38	2038		
	38	2039		
	38	2040		
	38	2041		
	38	2042		
	38	2043		
	38	2044		
	38	2045		
	38	2046		
	38	2047		
	38	2048		
	38	2049		
	38	2050		
	38	2051		
	38	2052		
	38	2053		
	38	2054		
	38	2055		
	7	2056		

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Common Liability (1072.0.3)	**No Data**			Non-nuclear liability insurance
Emissions Credits (1075.0.0)	No credits currently available			Credits available to nuclear plant owners should legislation prevail which would allow nuclear plant owners to trade away emissions credits for cash. Emissions could include carbon, NOx, SOx, VOC, Hg, etc.

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
G&A (1077.0.1)	747.9	2015	(1)Dominion Study Table 3-7 *O&M Cost Calculations* (2) Dominion Study Table 4-12 *ABWR DECCON Decommissioning Estimates*	Contingency to account for overhead expenses not carried in other production accounts. An amount of $3.5M is chosen based on the Dominion Study (historical experience)
	750	2016		
	750	2017		
	750	2018		
	750	2019		
	750	2020		
	750	2021		
	750	2022		
	750	2023		
	750	2024		
	750	2025		
	750	2026		
	750	2027		
	750	2028		
	750	2029		
	750	2030		
	750	2031		
	750	2032		
	750	2033		
	750	2034		
	750	2035		
	750	2036		
	750	2037		
	750	2038		
	750	2039		
	750	2040		
	750	2041		
	750	2042		
	750	2043		
	750	2044		
	750	2045		
	750	2046		
	750	2047		
	750	2048		
	750	2049		
	750	2050		
	750	2051		
	750	2052		
	750	2053		
	750	2054		
	750	2055		
	140	2056		

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
All Other O&M Costs (1077.0.2)	747.9	2015		Same as G&A
	750	2016		
	750	2017		
	750	2018		
	750	2019		
	750	2020		
	750	2021		
	750	2022		
	750	2023		
	750	2024		
	750	2025		
	750	2026		
	750	2027		
	750	2028		
	750	2029		
	750	2030		
	750	2031		
	750	2032		
	750	2033		
	750	2034		
	750	2035		
	750	2036		
	750	2037		
	750	2038		
	750	2039		
	750	2040		
	750	2041		
	750	2042		
	750	2043		
	750	2044		
	750	2045		
	750	2046		
	750	2047		
	750	2048		
	750	2049		
	750	2050		
	750	2051		
	750	2052		
	750	2053		
	750	2054		
	750	2055		
	140	2056		

Classification: Production Cost Accounts (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Depreciation and Amortization (1100.0.0)	**Factor .024** **Factor .005**	2015-2055 2056		This account depreciates the capital investment in the plant over a 40 year life time at a uniform rate**. The investments depreciated are**: *Planning & Management (2040.2.1)* *Permits & Approvals (2040.2.2)* *NSSS Design and Engineering (2040.2.3)* *Construction (2040.2.4)* *Capitalized* Interest (2040.2.5) The amortization factor is multiplied by the total investment in each category above beginning with commercial operation

Classification: Tax Accounts

These accounts calculate income taxes for Federal, State and Local jurisdictions

Federal Income Tax (1200.0.2)	Use Tax Rate per 2004 Federal Income Tax structure (see column 5). In most cases the 35% bracket is applicable.	All Periods	IRS	2004 Federal Income tax rate structure is: <$50K 15% $50K-$75K 25% $75K-$100K 34% $100K-$335K 39% $335K-$10M 34% $10M-$15M 35% $15M -$18.3M 38% >$18.3M 35% **FIT = tax rate X PBT**
State Income Tax (1200.0.2)	0**%**	All Periods		Texas does not have a State income tax
Local Income Tax (1200.0.3)	.18%	All periods	*Taxing Metropolis: Tax Capacity and Tax Effort in Large U.S. Cities Table A4 (http://www.ibo.nyc.ny.us/iboreports/taxcapacity215.pdf)*	Business income in Houston is taxed at a rate of $0.18 per $100 of taxable income .(18%)

Classification: Permits & Approvals Costs

This class of inputs is the cost of securing permits for the construction of the nuclear plant.

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Early Site Permit (610.0.1)	No Data			The project intends to co-site with an operating nuclear plant
Design Certification (610.0.2)	No Data			The only designs being considered are those which are either certified or near-certified
Combined License (610.0.3)	\$400 \$25,212	2006 2007	Suppliers confidential information & Dominion 10CFR170.21 *Title 10, Code of Federal Regulations*	Estimated cost of acquiring COLA from private sources

Classification: Permits & Approvals Costs (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Transmission Siting Studies (610.0.4)	No Data			Need more study on transmission construction. It most likely will be needed and will have to be added to project later.

Classification: NSSS Technology and Procurement

This is the cost of submitting and reviewing bids for the NSSS.

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Prepare NSSS Bids (620.0.1)	$3,500	2005	Suppliers confidential information & Dominion	Estimated from private sources
Bid Review (620.0.2)	$1,000	2006	Suppliers confidential information & Dominion	Estimated from private sources

Classification: Construction Costs

This is the cost of engineering the NSSS design, preparing the site, procuring the equipment, designing the plant, constructing the plant, loading the plant with fuel, training the reactor operators and starting up the plant. All of these costs are included in a construction loan with IDC (interest during construction) capitalized and amortized over the operating life of the plant .

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Transmission (630.0.1)	No Data			Data on transmission will be entered in later date if found necessary
EPC & Fuel Load (630.0.2)	76,882.2 259,477.4 1,140,488.0 438,937.9 70,611.1	2010 2011 2012 2013 2014	Suppliers confidential information from Task 3 with the assumption that 80% of capital cost is for construction and 20% is for NSSS System Design and Engineering	S Shaped construction curve

Classification: Construction Costs (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Startup (630.0.3)	$32170	2014	Dominion Study Table 3-7 *O&M Calculations*	
Training & Simulators (630.0.4)	$29,723 $33,190 $6,935 $3,468	2010 2011 2012 2013	Dominion Study Table 3-7 *O&M Calculations*	

Classification: Nuclear Fuel

This is the cost of procuring uranium ore, conversion to UF_6 , enrichment in U-235, fabrication into nuclear fuel and shipping to nuclear plant. The calculation of the amounts of uranium required in each phase of the process is determined by losses incurred in the transition processes, as well as the amount of uranium in the waste and product assays (i.e., enrichment) in the enrichment plant. It is assumed in the calculations below that an LWR is used; the ACR700 data would be somewhat different.

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Uranium Procurement (700.0.1)		07Q4	*(1)Nuclear Engineering International 2003* *(2)* Table 5.3 from Chapter 5, *The Calculation of Total Fuel Costs for PWR* in *The Economics of the Nuclear Fuel Cycle*, OECD (*http://www.nea.fr/html/ndd/reports/efc/EFC-complete.pdf*) *(3) The Nuclear Fuel Cycle Calculator, (http://www.antenna.nl/wise/uranium/nfcc.html)*	K6 & K7 (ABWR) fuel inventory is 150 MTU for 1356 MWe implying 9.04MW/MTU. For 1250 MWe plant initial fuel inventory would be 138.3 MTU. This requires 2,581,626 pounds of U_3O_8 ore be mined (see reference 3) at a cost of \$11 per pound of U_3O_8. 2,581,626 X \$11 =\$28,398K. This is purchased 2.5 years ahead of startup (See reference 2 for fuel cycle schedules). Startup is 09Q4.(

Classification: Nuclear Fuel (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Uranium Procurement (700.0.1)	$43,286	2012	*(1)Nuclear Engineering International 2003, Page 164* *(2)* Table 5.3 from Chapter 5, *The Calculation of Total Fuel Costs for PWR* in *The Economics of the Nuclear Fuel Cycle*, OECD (*http://www.nea.fr/html/ndd/reports/efc/EFC-complete.pdf*) *(3) The Nuclear Fuel Cycle Calculator, (http://www.antenna.nl/wise/uranium/nfcc.html)*	
	$0	2013		
	$0	2014		
	$0	2015		
	$18,672	2016		
	$0	2017		
	$18,672	2018		
	$18,672	2019		
	$0	2020		
	$18,672	2021		
	$18,672	2022		
	$0	2023		
	$18,672	2024		
	$18,672	2025		
	$0	2026		
	$18,672	2027		
	$0	2028		
	$18,672	2029		
	$18,672	2030		
	$0	2031		
	$18,672	2032		
	$18,672	2033		
	$0	2034		
	$18,672	2035		
	$18,672	2036		
	$0	2037		
	$18,672	2038		
	$0	2039		
	$18,672	2040		
	$18,672	2041		
	$0	2042		
	$18,672	2043		
	$18,672	2044		
	$0	2045		
	$18,672	2046		
	$18,672	2047		
	$0	2048		
	$18,672	2049		
	$0	2050		
	$18,672	2051		
	$18,672	2052		
	$0	2053		
	$0	2054		
	$0	2055		
	$0	2056		

Classification: Nuclear Fuel (cont'd)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Uranium Conversion (700.0.2)	$0	2012	*(1)* Table 5.3 from Chapter 5, *The Calculation of Total Fuel Costs for PWR* in *The Economics of the Nuclear Fuel Cycle*, OECD (*http://www.nea.fr/html/ndd/reports/efc/EFC-complete.pdf*) *(2) The Nuclear Fuel Cycle Calculator, (http://www.antenna.nl/wise/uranium/nfcc.html)*	.
	$7,011	2013		
	$0	2014		
	$0	2015		
	$0	2016		
	$3,024	2017		
	$3,024	2018		
	$0	2019		
	$3,024	2020		
	$3,024	2021		
	$0	2022		
	$3,024	2023		
	$3,024	2024		
	$0	2025		
	$3,024	2026		
	$0	2027		
	$3,024	2028		
	$3,024	2029		
	$0	2030		
	$3,024	2031		
	$3,024	2032		
	$0	2033		
	$3,024	2034		
	$3,024	2035		
	$0	2036		
	$3,024	2037		
	$0	2038		
	$3,024	2039		
	$3,024	2040		
	$0	2041		
	$3,024	2042		
	$3,024	2043		
	$0	2044		
	$3,024	2045		
	$3,024	2046		
	$0	2047		
	$3,024	2048		
	$3,024	2049		
	$0	2050		
	$3,024	2051		
	$0	2052		
	$3,024	2053		
	$0	2054		
	$0	2055		
	$0	2056		

Classification: Nuclear Fuel (cont'd

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Uranium Enrichment (700.0.3)	$0	2012	*(1)* Table 5.3 from Chapter 5, *The Calculation of Total Fuel Costs for PWR* in *The Economics of the Nuclear Fuel Cycle*, OECD (*http://www.nea.fr/html/ndd/reports/efc/EFC-complete.pdf*) *(2) The Nuclear Fuel Cycle Calculator, (http://www.antenna.nl/wise/uranium/nfcc.html)*	
	$44,395	2013		
	$0	2014		
	$0	2015		
	$0	2016		
	$22,184	2017		
	$0	2018		
	$22,184	2019		
	$22,184	2020		
	$0	2021		
	$22,184	2022		
	$22,184	2023		
	$0	2024		
	$22,184	2025		
	$22,184	2026		
	$0	2027		
	$22,184	2028		
	$0	2029		
	$22,184	2030		
	$22,184	2031		
	$0	2032		
	$22,184	2033		
	$22,184	2034		
	$0	2035		
	$22,184	2036		
	$22,184	2037		
	$0	2038		
	$22,184	2039		
	$0	2040		
	$22,184	2041		
	$22,184	2042		
	$0	2043		
	$22,184	2044		
	$22,184	2045		
	$0	2046		
	$22,184	2047		
	$22,184	2048		
	$0	2049		
	$22,184	2050		
	$0	2051		
	$22,184	2052		
	$22,184	2053		
	$0	2054		
	$0	2055		
	$0	2056		

Classification: Nuclear Fuel (cont'd

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Uranium Fabrication & Shipping (700.0.4)	$0	2012	*(1)* Table 5.3 from Chapter 5, *The Calculation of Total Fuel Costs for PWR* in *The Economics of the Nuclear Fuel Cycle*, OECD (*http://www.nea.fr/html/ndd/reports/efc/EFC-complete.pdf*) *(2) The Nuclear Fuel Cycle Calculator, (http://www.antenna.nl/wise/uranium/nfcc.html)*	
	$0	2013		
	$55,617	2014		
	$0	2015		
	$0	2016		
	$0	2017		
	$55,617	2018		
	$55,617	2019		
	$0	2020		
	$55,617	2021		
	$55,617	2022		
	$0	2023		
	$55,617	2024		
	$55,617	2025		
	$0	2026		
	$55,617	2027		
	$0	2028		
	$55,617	2029		
	$55,617	2030		
	$0	2031		
	$55,617	2032		
	$55,617	2033		
	$0	2034		
	$55,617	2035		
	$55,617	2036		
	$0	2037		
	$55,617	2038		
	$0	2039		
	$55,617	2040		
	$55,617	2041		
	$0	2042		
	$55,617	2043		
	$55,617	2044		
	$0	2045		
	$55,617	2046		
	$55,617	2047		
	$0	2048		
	$55,617	2049		
	$55,617	2050		
	$0	2051		
	$55,617	2052		
	$0	2053		
	$55,617	2054		
	$0	2055		
	$0	2056		

Classification: Spent Fuel Reprocessing

When using a reprocessing cycle, this account maintains the value of the spent fuel in terms of reprocessing the uranium, plutonium and other heavy metals. It is not used in a disposal cycle (which is the current condition in the U.S.). Spent fuel shipping in a disposal cycle is part of the decommissioning process and is accounted for in those accounts.

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Spent Fuel Storage (710.0.1)	No Data			This account is used only when reprocessing is in use. When this occurs, this account maintains the value of the heavy metals in the spent fuel assemblies. With a disposal cycle, this account is not used.
Spent Fuel Shipping (710.0.2)	No Data			This account is the cost of shipping spent nuclear fuel to be reprocessed. Not used when a disposal cycle is being used.
Other Spent Fuel Disposal Costs (710.0.3)	No Data			This account accrues all other costs associated with reprocessing spent fuel.

Classification: Other Balance Sheet Accounts

These are costs entered into Asset and liability accounts (stock accounts)

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Accounts Receivable (2020.0.10)	74.5 Days of Revenues	All periods	*Almanac of Business and Industrial Financial Ratio*s, Leo Troy, Aspen Publishers, Page 17	A working capital account that accrues costs owed to the power plant. It is typically specified as the number of days of revenue to which it equates. For large electric utilities with assets exceeding $250M the receivables turnover ratio in 2003 was 4.9. The number of days of receivables outstanding is computed from this number as: # Days Receivables = 365/receivable turnover ratio= 365/4.9 =74.5 days
Accounts Payable (2500.0.1)	67.1 days	All Periods	*Almanac of Business and Industrial Financial Ratio*s, Leo Troy, Aspen Publishers, Page 17	A working capital account similar to accounts receivable (above) except it represents funds the plant owes to its creditors. The current ratio for large electric utilities is 0.9, so accounts payable can be assumed to 0.9X Days of receivables =67.1 days

Classification: Other Balance Sheet Accounts

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Interest During Construction (2040.1.5)	7.07% real	2005-2015	UC Study	Assumes construction loan at prime 4.75% nominal and 5% risk premium nominal. Real rate is 7.07% using a 2.5% rate of inflation.

Classification: Other Balance Sheet Accounts

Description (Account Number)	**Data Used**	**Period**	**Data Source**	**Comments**
Interest on Long term Debt (2560.2.2)	3.22% real	2015-2056		20 year corporate bond is 5.81% nominal from WSJ.
Interest on Fuel Debt (2060.2.3)	7.3% real	2012-2056		This is a revolving loan to finance the cost of nuclear fuel as it is incurred. Nuclear fuel can be leased as well, but that option is not used very frequently anymore. A nominal 10% interest rate is equivalent to a real 7.32% rate of interest if a 2.5% rate of inflation is used 1.10/1.025 ~ 7.32%

TASK 8 APPENDIX

APPENDIX 8A. SAFETY AND PLANT PERFORMANCE

We think this figure nicely illustrates the point that safety and plant performance go hand in hand and are not at odds with one another. It is interesting to note that the improvements began when states began to deregulate electric utilities.

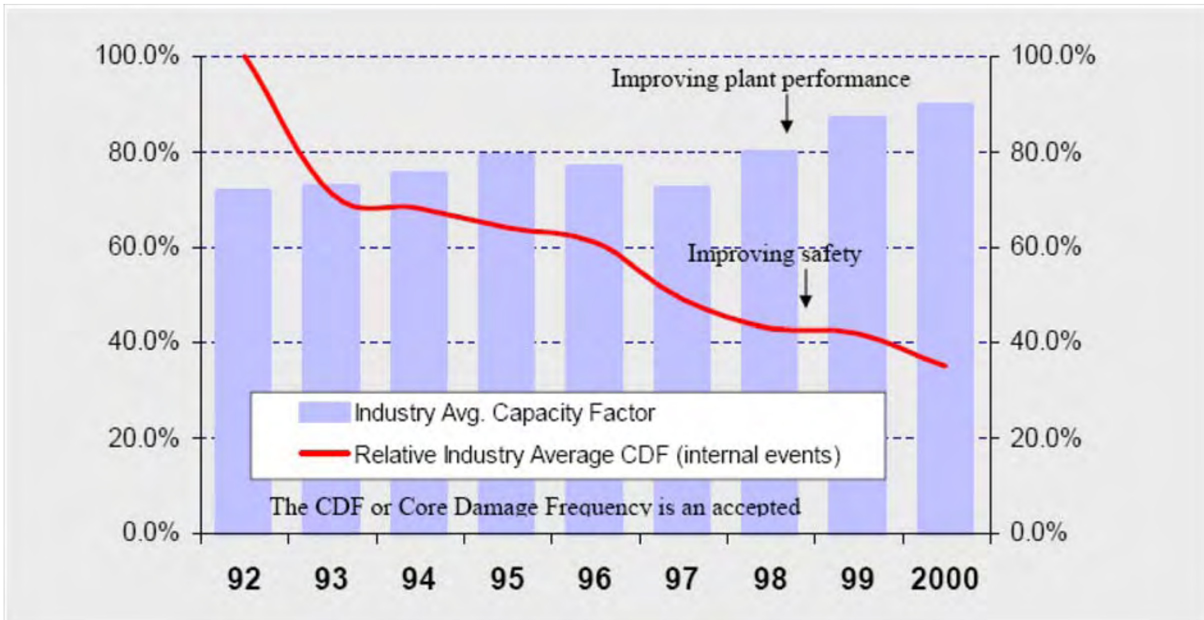


Figure 8A-1. Safety and Plant Performance are Not at Odds with One Another.