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U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Attention: Mr. David L. Meyer, Chief
Rules Review and Directives Branch
Division of Freedom of Information and
Publications Services

Subject: YANKEE ATOMIC ELECTRIC COMPANY COMMENTS ON NRC DRAFT NUREG/CR-5884, "REVISED ANALYSES OF DECOMMISSIONING FOR THE REFERENCE PRESSURIZED WATER REACTOR POWER STATION," AND DRAFT NUREG/CR-6054, "ESTIMATING PRESSURIZED WATER REACTOR DECOMMISSIONING COSTS," 58FR54385 (OCTOBER 21, 1993)

Dear Mr. Meyer:

Yankee Atomic Electric Company (YAEC) appreciates the opportunity to submit comments in response to the U.S. Nuclear Regulatory Commission's (NRC) request for comments on draft NUREG/CR-5884, "Revised Analyses of Decommissioning for the Reference Pressurized Water Reactor Power Station," Volumes 1 and 2 and on draft NUREG/CR-6054, "Estimating Pressurized Water Reactor Decommissioning Costs." YAEC is the owner of the Yankee Nuclear Power Station (YNPS) in Rowe, Massachusetts and provides engineering and licensing services to nuclear power plants in New England.

YNPS is currently in the process of decommissioning. A plan was submitted to the NRC in December, 1993. Several components have been removed or are in the process of being removed and include four steam generators, one pressurizer and all reactor vessel internal components.

It is YAEC's position that the subject report, NUREG/CR-5884 does not present an accurate assessment of the total costs required to "remove (as a facility) safely from service and reduce residual radioactivity to a level that permits release of the property for

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unrestricted use and termination of license," as currently defined in 10 CFR 50.2. The basis for this position is summarized below, with our detailed specific comments provided as Enclosure 1 to this letter.

The Executive Summary to NUREG/CR-5884 states that "the purpose of this study is to provide current bases for the reasonableness of decommissioning cost estimates." Because economic and financial considerations vary from utility to utility, any cost estimating approach other than "constant dollar methodology" serves to complicate the cost estimate analysis. Accordingly, it is YAEC's position that the report's inclusion of the effect of the time-value of money or net discount rates is unnecessary and possibly misleading for arriving at a reasonably accurate decommissioning cost estimate. Therefore Yankee recommends that the report's focus be on arriving at an accurate assessment of decommissioning costs, and not on attempting to draw conclusions from analyses which utilize assumed interest rates and rates of return.

YAEC's review and comparison of the study with our decommissioning experience to date, indicates that the study utilizes optimistic approaches and assumptions which result in understated decommissioning cost estimates and schedule durations. Some examples of these approaches and assumptions include the following:

- Section 3.2, "Reactor Deactivation for Safe Storage -- Period 2," includes overlapping activity sequences, aggressive activity durations, and low resource requirements. Reactor defueling, followed by the simultaneous processing of reactor coolant system water (RCS), performing an RCS chemical decontamination, performing systems layup, and preparing for and segmenting reactor core internals in the refueling cavity, all within a 32 week timeframe, is unrealistic and not consistent with YAEC's experience.

- The cost for removal of the reactor vessel and reactor core components is inordinately low. The reported costs of reactor internals and reactor pressure vessel removal, \$395,187 and \$109,756 (1993 \$, excluding contingency), respectively, compares with YAEC decommissioning cost estimates of \$1,434,000 and \$3,207,000 (1992 \$, excluding contingency), for the same activities conducted in the same relative timeframe after final shutdown.

- The generic use of 15-foot pipe lengths for piping systems removal, regardless of pipe diameter or weight, is unrealistic. At 542 lbs/ft, it is unlikely that 24-inch Schedule 160 pipe will be routinely handled in 15-foot lengths weighing more than 8000 lbs. In most circumstances 15-foot sections of pipe will be unwieldy and not consistent with reasonable rigging, handling, and egress requirements. An average length of 5 feet is a more appropriate generic length.

- The report excludes systems, equipment, and components which must be removed and whose removal would increase decommissioning costs. Actual radiological characterization data from YNPS indicates that many other systems may require decontamination such as the Feedwater System inside containment, Purification, Primary Plant Sampling, and Primary Plant Vent and Drain System. Also, the exclusion of contaminated pipe supports and hangers does not appear realistic, and will need to be incorporated into decommissioning cost estimates. Supports and hangers, especially those associated with larger pipes and components, represent a significant volume and weight that must be accommodated.

The subject report also raises the issue of whether costs associated with the storage of spent fuel after final shutdown are operating or decommissioning expenses. The report incorporates only 10% of these costs in the decommissioning estimates. 10 CFR 50.54(bb) states that each licensee is responsible "to manage and provide funding for the management of all irradiated fuel at the reactor upon expiration of the reactor operating license until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository." Accordingly, it is YAEC's position that all costs associated with the on-site storage of spent fuel, until possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository, are legitimate decommissioning expenses which should appropriately be included in decommissioning cost estimates. This approach establishes a basis for each licensee to establish a decommissioning strategy and cost estimate which incorporates all site-specific, post-shutdown activities into one integrated plan.

YAEC's decommissioning experience to date demonstrates that the basic assumption that cost estimates for a reference plant could and would serve as a benchmark for the entire industry is not valid. A general model that incorporates reference plant calculations in combination with other available regional and plant empirical data regarding decommissioning costs, however, is useful to provide a plant specific funding estimate for use in satisfying the regulation.

In summary, it is YAEC's position that NUREG/CR-5884 must be revised if it is to provide a reasonable basis for estimating decommissioning costs for pressurized water reactors. Each facility will have unique requirements or constraints associated with the ultimate dismantlement and decommissioning of the unit. Such unique characteristics may include the unavailability of various modes of transportation such as barge or rail, unique waste volumes resulting from operational characteristics or events, different low level waste transportation and disposal costs, and widely varying spent fuel storage strategies based upon site specific parameters or DOE fuel acceptance rates. Consideration should be given to providing a method for bounding or adjusting for such constraints.

Should you have any questions, or desire additional information regarding our comments on the subject NUREG, please contact me. YAEC is prepared to discuss these comments with your staff if you so desire.

Sincerely,

YANKEE ATOMIC ELECTRIC COMPANY

Russell Mellor
Project Manager
Yankee Rowe Project

RM/dhm
Enclosure (1)

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bc: A. Kadak
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ENCLOSURE 1
YANKEE COMMENTS
ON
NUREG/CR-5884 VOLUMES 1 & 2

"Revised Analyses of Decommissioning for the Reference Pressurized Water Reactor Power Stations"

1. The report does not provide a cautionary statement regarding its use. Such a cautionary statement should be included in the executive summary and at the beginning of the report. The statement should make the following two points:

   - The report is to be used as a guide and not as a "benchmark" for estimating the decommissioning costs associated with other facilities.

   - The conclusions and decommissioning costs reported in NUREG/CR-5884 are specific to the reference PWR for the scenarios analyzed. They do not represent the conclusions and decommissioning costs which have been or could be obtained for a real facility, including the Trojan Plant, which serves as the model for the reference PWR.

   Decommissioning strategies and their attendant costs require many assumptions and input parameters each of which have greatly varying levels of uncertainty. Additionally, each nuclear facility represents a unique situation with respect to size, location, single vs multi-unit site, years of operation, corporate structure, etc. Thus, the report should be considered only as a guide and its conclusions and decommissioning costs limited only to the special case that it represents.

2. The basic underlying assumptions for dismantling are not clearly stated in the report. The use of crew-hours as a resource measure is confusing and misleading. Shift length, shifts per workday, workdays per week need to be clearly stated in the beginning of the report. For example, the report has decommissioning activities which rely on three shift operation, such as internals removal. Obviously, the work philosophy/strategy directly affects period dependent costs and may affect activity dependent costs as pointed out below.

3. Reactor vessel internals removal is presented as a three shift operation, with two cutting crews on two shifts and packaging and disposal occurring on the third. This may be too optimistic. The assumption that four cutting-crew's worth of disposal can be accomplished on the backshift appears to be overly optimistic. In this regard, cask availability, which is a determining factor, is not even addressed. Additionally, although there is sufficient room available for two cutting operations at the reference PWR, this may not be the case at other facilities. Our

decommissioning experience makes us question the practicality of running simultaneous cutting operations.

4. Period 2, Reactor Deactivation For Safe Storage, includes overlapping activity sequences and aggressive activity durations. Reactor defueling, followed by the simultaneous processing of reactor coolant system (RCS) water , performing an RCS chemical decontamination, performing systems layup, and preparing for and segmenting reactor core internals in the refueling cavity, all withing a 32 week timeframe, is considered extremely optimistic. This duration compares with more than 32 weeks currently projected for the segmentation and disposal of the Yankee core internals, which are smaller than Trojan's. We seriously question the ability to perform many of these activities in parallel. The report needs to better explain the sequence of these activities.

5. Assumptions used in the development of unit cost factors may be unrealistic. For example, the unit cost factors for pipe removal were developed on the basis of removing 15-foot lengths of pipe per cut. This appears to be extremely unrealistic. Using this value, the number of piping cuts required will be significantly underestimated. Moreover, use of the 15-foot value in the report gives a false impression that it is readily achievable. It would be better to base piping removal costs on the 5-foot value and achieving an average cut longer than that would result in a cost savings. Additionally, consider the handling requirement differences between a 5 and 15-foot section of pipe. A 24" Schedule 160 pipe weighs 542 lbs/ft. It is much easier to handle and maneuver a 5-foot piece weighing 2700 lbs as opposed to a 15-foot piece weighing 8100 lbs. To assume pipe removal costs based on a 15-foot length cut may not be appropriate.

6. The reported cost for reactor internals removal is \$395,187, and \$109,756 for reactor pressure vessel removal (1993 \$, excluding contingency), as presented in Volume 2, Table C.1. This compares with Yankee decommissioning cost estimates of \$1,434,000 and \$3,207,000 (1992 \$, excluding contingency), for the same activities conducted in the same relative timeframe after final plant shutdown. (Based on an order of magnitude comparison, one would expect the reactor vessel removal cost to be at least comparable to or higher than the cost of steam generator removal. Table C.1 presents direct removal costs for steam generators as \$4,790,297, or approximately \$1.2 Million per generator. Compared to this estimate, the \$109,756 estimate for reactor vessel removal appears unrealistic).

7. Removal of contaminated or noncontaminated asbestos to access contaminated systems can be a significant decommissioning cost. The report assumes an insignificant amount of asbestos is present in the reference plant at the time of decommissioning. This assumption cannot be generally applied even with the asbestos removal programs in place today. Other hazardous materials exist which

need to have their removal cost properly characterized (e.g., chromates, PCBs, lead, etc.)

8. The handling of SNF appears to be reasonable. However, it needs to be strongly emphasized that no progress has been made by DOE in siting an MRS and that the linkage of MRS operation to the repository still exists. This makes acceptance of SNF by DOE in 1998 improbable and even casts doubt on the acceptance of reference PWR SNF in CY-2002.

9. The report should only be based on constant dollars and refrain from any economic predictions. This will preclude economic predictions from skewing report results and making one decommissioning scenario look financially better than another. Users of the report can then better evaluate the economic impact of the published decommissioning scenarios. Since economic and financial considerations will vary from utility to utility, any cost estimating approach other than "constant dollar methodology" will only serve to complicate the analysis.

10. The report's assessment of the impact of the time value of money is misleading (Sections 3.5.2 and D.4.3):

- First, use of the net discount rate (interest - inflation) is inappropriate for assessing decommissioning fund requirements (especially in Section 3.5.2). The net earnings rate (fund earnings rate - average decommissioning cost escalation rate) must be used in present value determinations. This is extremely important because decommissioning costs do not necessarily escalate with inflation but escalate according to the cost escalation experienced by each decommissioning cost component: energy, labor, material, LLW burial, etc..

- Second, assuming a 3% net earnings rate differential (see above definition) is unrealistic given the escalation in decommissioning costs, especially LLW burial costs. A net earnings rate of 1% or less may be more appropriate, however, it is very possible to have a negative earnings rate differential which means fund contributions would have to increase to cover decommissioning cost escalation.

- Additionally, utilities under FERC jurisdiction can only invest decommissioning funds in a limited number of secure investment vehicles whose earnings are only slightly above inflation (and most likely less than the decommissioning cost escalation rate). For these utilities, it may be necessary to plan on a negative earnings rate differential versus the decommissioning cost escalation rate.

- Because of the above factors, the difference in total cost of decommissioning determined by the present value method, $101.6 Million, and the constant dollar method, $124.6 Million, really does not exist. Stating that funding based on the constant dollar method results in a 22% overestimate of funding needs for DECON and provides a significant safety margin may be overly optimistic.

- Use of the net discount rate in Section D.4.3 for determining the life cycle costs associated with SNF storage options may be appropriate if the cost components for SNF storage options track with inflation. However, using a value of 3% for the net discount rate may be too optimistic for reasons stated above.

- The conclusion given in the Executive Summary and in Section 6 that SAFSTOR is less expensive than the DECON alternative based on present value is misleading because of the unrealistic differential earnings rate used in the analysis (i.e., 3% net discount rate). Given the above arguments supporting little, if any, differential earnings, the DECON option becomes much more attractive. This is because DECON minimizes the length of decommissioning and affords utilities a measure of protection against rampant escalation of decommissioning costs.

11. The subject report also raises the issue of whether costs associated with the storage of spent fuel after final shutdown are operating or decommissioning expenses. The report incorporates only 10% of these costs in the decommissioning estimates. 10 CFR 50.54(bb) states that each licensee is responsible "to manage and provide funding for the management of all irradiated fuel at the reactor upon expiration of the reactor operating license until title to the irradiated fuel and possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository." Accordingly, it is YAEC's position that all costs associated with the on-site storage of spent fuel, until possession of the fuel is transferred to the Secretary of Energy for its ultimate disposal in a repository, are legitimate decommissioning expenses which should appropriately be included in decommissioning cost estimates. This approach establishes a basis for each licensee to establish a decommissioning strategy and cost estimate which incorporates all site-specific, post-shutdown activities into one integrated plan.

12. Tables 3.2 and 3.3 give the estimated utility and Decommissioning Operations Contractor (DOC) staffing requirements for DECON in terms of person-years per period which is used to arrive at staffing costs. However, the term does not readily convey actual staffing requirements. For example, Table 3.2 requires 112 persons-years of utility staffing for Period 2 which translates into 182 persons (112 person-years divided by a period length of 0.62 years). These tables should

readily reflect the total staff required during any given period and not just the integrated person-years which, when given by itself, can be misleading.

13. There are no DOC staffing requirements listed in Table 3.3 for DECON Period 2 during which three major decommissioning activities are taking place: chemical decontamination, internals segmentation, and systems deactivation. This is a highly unrealistic assumption, especially when considering the fact that only 3 equivalent utility people have been assisting 19 DOC staff in DECON Period 1 preparing for these activities. Even though specialty contractors are involved, it is Yankee's experience that a significant amount of DOC staff is required to assist DECON Period 2 activities. An implicit (and very unrealistic) assumption embedded here is that uninvolved utility staff can just turn into decommissioning "gear" during Period 2 without any involvement in Period 1 preparation activities.

14. The duration of DECON Period 3 is 6.3 years. The report assumes that the DOC staff in place at the end of Period 1 simply restarts activities 6-months prior to the end of Period 3 to begin preparation for dismantlement activities in DECON Period 4. This start-up time seems to be insufficient. Consider the following: (1) magnitude of Period 4 activities, (2) the DOC has not been active for 5.8 years, (3) the Period 4 DOC may not be the same contractor as the Period 1 DOC, and (4) even if the DOC is the same contractor, the staff may be entirely different. Additionally, decommissioning status and available activitiy options could change dramatically over the Period 3 time period, necessitating a thorough review of planned activities. This plus the previously mentioned factors would support restarting DOC activities much earlier in Period 3 than assumed in the report.

15. The staffing levels for all DECON periods appear to be low when compared to recent decommissioning experience. DOC plus utility staff levels for Periods 1-5 are 22, 180, 5, 24, and 85 respectively. Although the decommissioning schedule is different from the Yankee schedule, the report's assumed staffing levels are low when compared against Yankee staffing estimates for periods with comparable activities. For instance, the DOC plus utility staff level assumed in the report during Period 4 (when a majority of plant dismantlement occurs) is about one-half that assumed for Yankee Rowe, a plant that is approximately 1/5th the megawatt rating of the reference plant. Scaling on the basis of size may result in overestimating actual staffing requirements. However, one would expect, at a minimum, a comparable staffing level.

16. DECON Period 1 costs are not fully explained in Section 3.1. The total cost for DECON Period 1 given in Table 3.1 is estimated at $9 Million. DOC and utility staff costs account for $5.4 Million while the balance ($3.6 Million) is not explained. Table C.1 reports this balance as being distributed between regulatory

costs ($0.4 Million) and special tools and equipment ($3.2 Million). The line items comprising the balance of DECON Period 1 costs are not identified nor is any explanation of these costs given in the report.

17. The overhead rate (42%) applied to utility salaries appears to be low. Overhead rates for utility staffs are dependent on many variables and should be determined on a case by case basis. Smaller, single asset companies may need to absorb a higher percentage of corporate indirect overhead costs than would a larger utility with many units. It would be beneficial for the report to include a listing of the components which comprise the overhead rate in order to clarify what is and what is not included in the 42%.

18. The economic evaluation of the life cycle costs of wet SNF storage vs dry SNF storage are provided in Appendix D, "Effects of the Spent Nuclear Fuel Inventory on Decommissioning Alternatives." The following specific comments are provided:

   a) There is no consideration given nor discussion provided on the impact these storage alternatives have on the overall decommissioning schedule and cost. Comparing only their life cycle costs fails to capture the impact on decommissioning schedule and cost. [For example: What is the overall strategy with keeping the pool running? Does the report assume decommissioning around the pool, release the balance of the site, and decommission the pool once all the SNF is gone? Or does the report assume that the SAFSTOR period simply gets extended? The overall strategy has a significant impact on the cost of decommissioning with either the pool or ISFSI option.]

   b) The report states (page D.2) that the minimum period for pool operation without an ISFSI is 14 years. Based on Table D.2 data, this 14-year minimum period is contingent on 193 SNF assemblies being removed in CY2029, the final year of pool operation. This will require "earlier" removal of the last of the reference plant's SNF by DOE. We fully support DOE giving priority to removal of SNF at shutdown facilities. It can be done without compromising SNF removal at other facilities.

   c) Assumptions used in the economic analysis presented in Section D.4.3 comparing the life cycle costs of the two SNF storage alternatives appear structured to favor keeping the spent fuel pool operational.

   d) It may not be correct to assume that the cost of deactivating and decommissioning the spent fuel pool after all the SNF is removed (CY2029) will be the same cost incurred during normal decommissioning. A significant penalty may be incurred due to the restart of decommissioning activities (i.e., a second set of mobilization and demobilization costs).

e) No consideration is given nor discussion provided on the impact of having to decommission "around" the spent fuel pool if it is left operational until CY2029. There will be constraints on decommissioning activities which will add to the cost of this alternative.

f) There is no basis given for the estimated $0.5 Million cost of separating spent fuel pool systems for the balance of the plant. This estimate appears to be very unrealistic. Having examined this option for Yankee (i.e., creating a spent fuel pool island separate from the rest of the plant), it appears that this estimate could be low by an order of magnitude! [One item for consideration is the licensing cost associated with separating the spent fuel pool and related systems and securing a Part 70 license. However, this is not necessary until the Part 50 license is relinquished.]

g) It is not always clear in Section D.4.3 as to whether the dollar amounts reported are constant value, present value, or future value, especially in the discussion presented on pages D.18 and D.19. As recommended in a previous comment, all costs should be reported in current year (1993) dollars.

h) As mentioned in a previous comment, use of the net discount rate in the economic analysis is misleading. It is really the differential earnings rate (earnings-escalation) that should be used. The 3% value assumed in the present value calculations is overly optimistic. Additionally, each option may have its own differential earnings rate based on how the cost of the option escalates.

i) The cost of SNF storage casks appears to be much higher than expected: $0.714 Million per cask ($35 Million/49 casks). A unit cost in the range of $300K-$400K per cask would appear more reasonable. This would reduce the cost of this option by about $15-$20 Million. [Note: it is not clear if cask unit cost is based on future or present value. If it is a future value number, then the unit cost per cask in present value dollars in about $0.581 Million. This would still represent a cost reduction in the range of $9-$14 Million for the option.]

Additionally, the $65/MTU or $35 million cost for the dry casks provided on page D.19 is inconsistent with the figures quoted in the 1989 Dry Cask Storage Study which was used as a reference. The costs cited in this Study were $45-$65/Kg for a 100 MTU facility and $40-$55/Kg for a 1000 MTU facility. The reference facility is about 500 MTU. The value used in the report appears to be much too conservative and the use of a lower value could be substantiated.

j) The estimated cost of $5 Million for the ISFSI's concrete storage pad and related equipment appears to be quite high. Conversely, the labor cost for removing SNF from the pool appears to be low by a factor of three. Furthermore, the cost to decommission the ISFSI is much higher than expected: $4 Million in year 15 or $2.6 Million in present value dollars. All that will be left of the ISFSI after all SNF is removed is the concrete pad, the surrounding fence, and transfer equipment (assuming DOE takes the concrete casks). Thus, the cost of decommissioning the ISFSI should be nominal (under $500K).

k) There is no line item representing real estate taxes in Table D.4, "Estimated SNF Storage Operational Costs at the Reference PWR." Although real estate taxes for the spent fuel pool and ISFSI will be similar, they should be included for completeness.

l) The report states, in the first paragraph on page D.1, that transfer to a dry ISFSI is constrained by allowable fuel cladding temperatures which necessitates an extended cooling period in water prior to transfer into dry storage. The report fails to mention that the transfer of SNF to a dry ISFSI is also constrained by the heat removal capability of the dry cask storage system. Furthermore, in the discussion on page D.21, thermal data for the assumed storage system was not discussed or mentioned. Proper matching of SNF heat load to dry cask heat removal capability is the real issue. Given the design constraints of cask heat removal capability, SNF burn-up/power density, number of SNF assemblies loaded, total heat load, and temperature limits, cask loading requirements should be readily determined. On this basis, it should be possible to transfer SNF to dry cask storage in a much shorter time frame than the 7-years cited in the report. Additionally, many of the currently licensed dry storage systems are licensed for 5 year cooled fuel. However, they are also licensed for maximum burnups in the 35-40,000 MWD/MTU range.

m) The conclusion at the end of Section D.5, page D.26, D.26 is that the spent fuel pool could not be emptied until at least 7 years following shutdown. However, no consideration has been given either to mixing SNF or partially filled casks as a way to reduce the time SNF remains in the spent fuel pool. It should be possible to license either a mix and match arrangement (older SNF with newer SNF) or derated casks (i.e., loading fewer assemblies) so long as the heat removal capability of the dry storage cask is not exceed.

n) Appendix D basically concludes that it is more cost effective to store SNF in the pool than to build a dry ISFSI. Yet the report assumes an ISFSI is built in CY2022. This is confusing. If the conclusion is valid, shouldn't the report follow its own conclusions and begin dismantling once all SNF would be removed from the pool (i.e., CY2029)?

o) Figure D.2, which compares the present value cost of the pool option vs. the ISFSI option, does not present a valid comparison. First, the use of the 3% discount rate distorts the comparison. Second, the assumptions favored the pool option more than the ISFSI option. Third, and most importantly, the comparison does not address the impact on the overall decommissioning cost and schedule.

p) The document should also consider the effect of the Multi-Purpose Canister System on decommissioning cost or at least recognize that it's implementation may affect such costs.

q) D.29 Paragraph following the three "bullets": Pacific Nuclear is in the process of licensing a cask to contain a leaking canister. The same cask is being licensed for transport.

19. The systems identified in the study for complete or partial removal comprise fewer systems and at a far lower cost than those identified for Yankee Nuclear Power Station. Actual radiological characterization data from Yankee indicates that many other systems, not listed in the study, will need to be decontaminated. Some of these systems include Feedwater inside containment, Purification, Primary Plant Sampling, Primary Plant Vent and Drain, Fuel Handling, steam generator blowdown, and Containment Heating and Cooling, to name a few. As a result, the total cost for removal and disposal of contaminated systems at Yankee has been estimated to be more than $25 Million compared to the study estimate of approximately $5 Million.

20. No effort was made in the study to quantify the number and characteristics of pipe hangers, under the assumption that most of the hangers are sufficiently small that they can be placed in the piping containers without further consideration. Yankee has estimated approximately 2500 small bore and 800 large bore pipe hangers as part of its preliminary contaminated equipment inventory. These quantities of pipe hangers represent a significant work effort and waste volume and, therefore, warrant a more rigorous cost engineering assessment than that contained in the study.