August 13, 1999

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

In the Matter of	)	
	)	
HYDRO RESOURCES, INC.	)	Docket No. 40-8968-ML
(2929 Coors Road, Suite 101	)	ASLBP No. 95-706-01-ML
Albuquerque, NM 87120)	)	
	)	

BRIEF OF INTERVENORS EASTERN NAVAJO DINÉ AGAINST URANIUM MINING AND SOUTHWEST RESEARCH AND INFORMATION CENTER

ON REVIEW OF PARTIAL INITIAL DECISION LBP-99-13, FINANCIAL ASSURANCE FOR DECOMMISSIONING

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Statutory Authority

Administrative Authority

Case Authority

STATEMENT OF THE CASE

A. Introduction

Hydro Resources, Inc. ("HRI") holds a source and byproduct materials license for the proposed Crownpoint in situ leach ("ISL") uranium mining project. HRI received this license from the Nuclear Regulatory Commission ("NRC") Staff without first submitting cost estimates, cost information, or a plan for decommissioning its mill and surface areas or restoring the groundwater contaminated by this project. The license merely directs HRI to submit, prior to commencing operations, a surety for some initial wells, based on a nine pore volume groundwater restoration effort. The NRC has not determined what a nine pore volume restoration effort would cost, has not determined what the amount of HRI's initial surety should be, and has not set a surety amount in HRI's license. HRI has not submitted a surety instrument for the project.

The NRC Staff, therefore, issued HRI's license in violation of the financial assurance requirements of 10 C.F.R. Part 40, Appendix A and 10 C.F.R. § 40.36. These regulations both require a license applicant to submit a financial assurance plan for decommissioning and to Commission approval of that plan prior to licensing. By neglecting to comply with these regulations, HRI's license unravels the statutory and regulatory regime establish by Congress and the NRC to hold licensees responsible for site decommissioning, by ensuring that mining licenses are not issued unless applicants are prepared to clean up their operations when they finish.

By approving the unlawfully issued license in LBP-99-13, the Presiding Officer

has committed plain and egregious legal error. HRI's failure to comply with the financial assurance rules in its license application warrants reversal of LBP-99-13, rejection of the license application and revocation of HRI's license.

B. Procedural Background

On April 13, 1988, HRI filed a license application for in situ leach ("ISL") uranium mining at three sites comprising the "Crownpoint Project": Church Rock, Unit 1, and Crownpoint. Application for Materials License (Hearing Record ACN 8805200339) (April 13, 1988). Intervenors Eastern Navajo Diné Against Uranium Mining ("ENDAUM") and Southwest Research and Information Center ("SRIC") requested a hearing on the license application in December, 1994, and amended their requests after the Final Environmental Impact Statement ("FEIS") was issued on February 29, 1997. NUREG-1508, Final Environmental Impact Statement to Construct and Operate the Crownpoint Uranium Solution Mining Project, Crownpoint, New Mexico (February 29, 1997) (Hearing Record ACN 9703200270); ENDAUM and SRIC's Second Amended Request For Hearing, Petition to Intervene, and Statement of Concerns (August 15, 1997).

On January 5, 1998, the NRC Staff issued license SUA-1508 to HRI. (Hearing Record ACN 9801160066), Addendum at 49. More than four months later, the Presiding Officer issued an order granting ENDAUM and SRIC standing as parties and admitting a number of their concerns for adjudication. LBP-98-9, 47 NRC 261, 266 (1998).

In June, 1998, HRI requested "bifurcation" of the proceeding on the basis that only Section 8 was ripe for a hearing because HRI "presently has firm plans to proceed only with Section 8" of the Church Rock mine site. (The rest of the Church Rock site lies within a portion of Section 17.) HRI's Request for Partial Clarification or Reconsideration of Presiding Officer's Memorandum and Order of May 13, 1998; and Request for Bifurcation of the Proceeding at 13 (June 4, 1998). In response, the Presiding Officer bifurcated this proceeding to address general licensing issues and issues related to half of the licensed Church Rock site, referred to as "Section 8". *Hydro Resources, Inc.*, Memorandum and Order, slip. op. at 2, (September 22, 1998).

On January 11, 1999, Intervenors filed a written presentation on their admitted concerns regarding the adequacy of HRI's financial surety. Eastern Navajo Diné Against Uranium Mining's and Southwest Research and Information Center's Brief in Opposition to Hydro Resources, Inc.'s Application for a Materials License with Respect to: Financial Assurance for Decommissioning ("Intervenors' Presentation"). Intervenors' Presentation was supported by the testimony of Dr. Michael F. Sheehan ("Sheehan Direct Testimony"). *Id.* at Exhibit 1. HRI filed its response on February 11, 1999. Hydro Resources Inc.'s Response to Intervenors' Briefs with Respect to Hydro Resources, Inc.'s Technical and Financial Qualifications and Financial Assurance for Decommissioning ("HRI Response Presentation"). The NRC Staff responded on February 18, 1999. NRC Staff's Response to Intervenors' Presentations on Technical Qualification, Financial, and

Decommissioning Issues ("Staff Response Presentation").

On March 10, 1999, the Presiding Officer issued LBP-99-13, denying Intervenors any relief "with respect to their area of concern related to financial assurance for decommissioning issues." *Id.* at 6. On March 30, 1999, ENDAUM and SRIC petitioned for review of LBP-99-13. HRI and the NRC Staff opposed the Petition for Review. NRC Staff's Response to Petition for Review of LBP-99-13 (April 14, 1999) ("Staff Response to Petition for Review"); Hydro Resources, Inc.'s ("HRI's") Opposition to Intervenors' Petition for Review of Presiding Officer's Partial Initial Decision LBP-99-13 (April 13, 1999) ("HRI Response to Petition for Review"). The Commission granted Intervernors' subsequent motion for leave to reply on May 3, 1999. On May 10, 1999, Intervenors submitted their reply ("Intervenors' Reply to Responses to Petition for Review"), supported by the additional testimony of Dr. Sheehan ("Sheehan Reply Testimony").

The Commission accepted review of LBP-99-13 in CLI-99-22 (July 23, 1999), which directs the parties to "submit briefs addressing the arguments raised in Intervenor's petition for review of LBP-99-13." *Hydro Resources, Inc.*, CLI-99-22, slip.op., at p. 24, 49 NRC ____ (July 23, 1999). In addition, the parties are to address the following questions in their briefs:

1) Was financial assurance information submitted by HRI adequate to meet the requirements for licensing?

2) If HRI is correct in its assertion that an approved financial

> assurance plan is not a pre-requisite to the issuance of a license, what is the meaning of the staff's assertion in its response that "the issue is thus not yet ripe for ... [the Presiding Officer's] ... review?"

CLI-99-22 at 24.

C. HRI's Provisions for Financial Surety

Neither the original environmental report for Church Rock, nor any of HRI's subsequent environmental reports, provides a decommissioning plan or cost estimates as required by Criterion 9 of Appendix A to Part 40. Nor does the license application contain a financial assurance plan, as required by 10 C.F.R. § 40.36. In its response to the NRC Staff's Request for Additional Information ("RAI") 92, HRI provided some project cost estimates concerning the cost/benefit analysis required by the NRC's National Environmental Policy Act ("NEPA") regulations. HRI Response to RAI 92 (Hearing Record ACN 9604260063) (April 5, 1996), Addendum at 53. One figure ($10,221,930) which is described as "Restoration and Decommissioning", is provided for all of the Church Rock site, Sections 8 and 17. *Id.* at 59. Although the HRI Response states that this figure is based on a four pore volume restoration effort, HRI fails to provide any breakdown of this cost estimate. *Id.* at 56. HRI fails to provide any cost estimates for groundwater restoration and decommissioning at the other Crownpoint Project sites (i.e. Unit 1 and Crownpoint). In 1997, HRI also submitted additional information, consisting of some draft surety instruments and a financial assurance plan for Section 8 that had been submitted to the New Mexico Environment Department ("NMED"). Letter from

D.L. Goodier, HRI to R. Carlson, NRC with enclosures (June 25, 1997) (ACN 9707020388); the Staff attached this information as Exhibit 1 to the Staff Response Presentation. The United States Environmental Protection Agency ("EPA") has determined that HRI must obtain its injection permit from EPA, not the NMED.[1] The submittal contained no information other than for a portion of the cost of subsurface groundwater restoration, monitoring and well plugging. *Id.*

In the FEIS, the NRC Staff states that before HRI can begin uranium recovery operations, "detailed restoration, reclamation, and decommissioning plans, related cost estimates, and an appropriate surety would be required." FEIS at 2-19. The FEIS also concludes that "practical production-scale groundwater restoration activities would at most require a 9 pore volume restoration effort" and that the surety would be "maintained at this level until the number of pore volumes required to restore the groundwater quality of a production-scale well field has been demonstrated by HRI." *Id.* at 4-40. The basis for the 9 pore volume figure is not that it is effective in restoring groundwater, but that adding more than 9 pore volumes would not have any additional beneficial effect. *Id.*

Financial assurance for decommissioning is addressed in HRI's license in Administrative Condition 9.5, which states in relevant part:

> As a prerequisite to operating under this license, the licensee shall submit an NRC-approved surety arrangement to cover the estimated costs of decommissioning, reclamation, and groundwater restoration. . . Surety for groundwater restoration of the initial well fields shall be based on 9 pore-

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[1] Sheehan Reply Testimony at 4 and note 1.

> volumes. Surety shall be maintained at this level until the number of pore volumes required to restore the groundwater quality of a production-scale well field has been established by the restoration demonstration described in LC 10.28.

Administrative Condition 9.5 is reproduced in its entirety in the Addendum at 50-51. Referring to the Churchrock groundwater restoration demonstration, license Condition 10.28 states that the "demonstration shall be conducted on a large enough scale . . . to determine the number of pore volumes that shall be required to restore a production-scale wellfield." *Id.* at 52.

STANDARD OF REVIEW

The Commission reviews the legal findings of licensing boards *de novo*. Factual determinations may be reversed if the record compels a different result. *General Public Utilities Nuclear Corporation* (Three Mile Island Nuclear Station, Unit 2), ALAB-926, 31 NRC 1, 13 (1990), *citing Niagra Mohawk Power Corp.* (Nine Mile Point Nuclear Station, Unit 2), ALAB-264, 1 NRC 347 357 (1975). The Commission, however, has "inherent authority to review and act upon any adjudicatory matter before a Commission tribunal--subject only to the constraints of action on the record and reasoned explanation of the conclusions." *Public Service Co. of New Hampshire* (Seabrook Station, Units 1 and 2), CLI-77-8, 5 NRC 503, 516 (1977). *See also Baltimore Gas & Electric Company* (Calvert Cliffs Nuclear Power Plant, Units 1 and 2), CLI-98-15, 48 NRC 45, 51 (1998); *Louisiana Energy Services* (Claiborne Enrichment Center), CLI-97-15, *slip op.*, at 7 note 7 (1997).

ARGUMENT

I. PRIOR TO LICENSING, A DECOMMISSIONING PLAN WITH COST ESTIMATES MUST BE SUBMITTED TO AND APPROVED BY THE COMMISSION.

It is undisputed that no Commission-approved cost estimate exists for the decommissioning of the Crownpoint Project. The question presented is whether the Presiding Officer erred in finding that HRI's license application nevertheless satisfies the requirements of Criterion 9, and provides reasonable assurance that public safety will be protected.[2] *See* LBP-99-13, slip.op., at 5-6 and at 3 ("HRI will not be permitted to commence operations until it has complied with 10 C.F.R. Part 40, Appendix A, Criterion 9; consequently, there is no reason to believe that issuance of the license is inimical to public safety"). The Presiding Officer's ruling that compliance with Criterion 9 can be deferred until after licensing constitutes plain legal error. Indeed, it ignores the plain language of Criterion 9, its rulemaking history, and the established practice of the NRC Staff, which clearly require approval of decommissioning cost estimates as a licensing determination.

A. HRI's License Application Fails to Meet the Requirements of 10 C.F.R. Part 40, Appendix A, Criterion 9.

1. The plain language of Criterion 9 requires pre-licensing approval of cost estimates and a decommissioning plan.

The language in Criterion 9 creates a two step process for the establishment of an

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[2] CLI-99-22 holds that 10 C.F.R. § 40.36 does not apply to this proceeding. Intervenors seek reconsideration of this holding, which is addressed in subsection C below.

adequate surety for milling operations.[3] First, in conjunction with the environmental report, the applicant must submit "Commission-approved cost estimates in a Commission-approved plan". 10 C.F.R. Part 40, Appendix A, Criterion 9.[4] Second, surety arrangements that are consistent with the approved plan must be in place prior to the commencement of operations. *Id.*

The rulemaking history of Criterion 9 makes it clear that the Commission intended to require pre-licensing approval of decommissioning plans and cost estimates prior to licensing. In conjunction with the issuance of Appendix A, Criterion 9, the NRC issued NUREG 0706, the Final Generic Environmental Impact Statement on Uranium Milling (April, 1979) ("GEIS").[5] The GEIS explains the process in Criterion 9 as follows:

> A plan for decommissioning of the mill buildings and site, and for disposing of the tailings, in accordance with requirements delineated

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[3] *See* Intervenors' Presentation at 18-19 for a more detailed discussion of this regulatory scheme.

[4] The use of the term "licensee" in this context is not significant as existing licensees at the time Appendix A was promulgated were also required to comply its requirements. *See* Uranium Mill Licensing Requirements, 45 Fed.Reg. 65521, 65530 (October 3, 1980) (Appendix A requires all mill operators to submit programs meeting the financial and technical criteria "in connection with license renewals or within nine months, whichever occurs first"). *See also* Final Generic Environmental Impact Statement, NUREG-0706 at 12-5. It is clear that the requirement applies to applicants as well as licensees.

[5] The Commission's response to public comments on the promulgation of Criterion 9 note that, "The detailed bases for the criteria in the new Appendix A are contained in the final GEIS." Uranium Mill Licensing Requirements, 45 Fed.Reg. 65521, 65529 (October 3, 1980).

above, must be proposed by applicants, and approved by appropriate agencies, before issuance or renewal of licenses.

Id. at 12-5 (emphasis added).

In this case, HRI's license application utterly fails to take the first step required by Criterion 9, submission of cost estimates and a decommissioning and reclamation plan, with the environmental report. None of the environmental reports submitted by HRI contain such a plan, let alone surety cost estimates.[6] The few financial documents in the record also fall far short of providing this information. *See, infra*, Section II.

2. In issuing HRI's license, the NRC Staff violated its own guidance and practice under Criterion 9.

LBP-99-13's approval of the HRI license application is inconsistent with NRC regulatory guidance interpreting Criterion 9. NUREG-1569, the Draft Standard Review Plan for In Situ Leach Uranium Extraction License Applications, Division of Waste Management Office of Nuclear Material Safety and Safeguards, (October, 1997) ("DSRP"), Addendum at 7. The DSRP explains in some detail what an applicant must provide in the financial assurance plan, before an ISL license can be issued. Section 6.5.1, Areas of Review, instructs that, "The Staff shall review financial assessments

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[6] Hydro Resources, Inc. Churchrock Project Environmental Report (April 13, 1988) (Hearing Record ACN 8805200344) ("1988 Churchrock ER"); Churchrock Project Revised Environmental Report (March 16, 1993) (Hearing Record ACN 9304130415) ("1993 Churchrock ER"); Crownpoint Project Technical Report and Analytical Summary (July 31, 1992) (Hearing Record ACN 9509080094) ("Crownpoint ER"); Unit 1 Environmental Assessment (Hearing Record ACN 9509080065) (January 6, 1992) ("Unit 1 ER").

provided by the applicant for the costs of groundwater restoration (section 6.1); reclamation (section 6.2); and decommissioning, waste disposal, and monitoring (section 6.4)." DSRP at 6-17, Addendum at 8 (emphasis added). *See also* Sections 6.5.2 (review procedures) and 6.5.3 (acceptance criteria) at 6-17, 6-18, Addendum at 8-9. Appendix E to the DSRP outlines the "detailed cost information necessary to verify the cost estimates for . . .categories of closure work. . ." DSRP at E-1, Addendum at 11. It explains,

> As required under Criteria 9 and 10 of 10 CFR Part 40, appendix A, the licensee shall supply sufficient information for the Nuclear Regulatory Commission (NRC) to verify that the amount of coverage provided for the financial assurance accounts for all necessary activities required under the license to allow the license to be terminated. Cost estimates for the following activities (where applicable) should be submitted to NRC with the initial license application or reclamation plan and should be updated annually as specified by the license.

Id. (emphasis added). Section 6.5.4 of the DSRP further proposes language to be included in the technical evaluation report in the event the Staff approves a surety plan. *Id.* at 6-18, 6-19. The DSRP's interpretation of Criterion 9 for ISL license applicants is not consistent with LBP-99-13.

In issuing HRI's license, the NRC Staff ignores its own established practice in approving ISL license applications. With respect to other ISL materials licenses, the Staff's practice has been to approve the cost-estimates in an applicant's financial assurance plan prior to licensing, and to require surety in a specific amount as a license condition. License SUA-1534 was issued for the Crow Butte Project on December 29, 1989. License Condition 27 required the licensee to submit a surety instrument for a

minimum of $4,877,550.00 within ninety days of issuance. Addendum at 18.

Likewise, license SUA-1540, for the North Butte project, was issued on December 21, 1990, after the Staff approved the applicant's cost estimates and surety plan. Addendum at 36. License condition 35 requires the licensee to submit a surety for $4,920,705.00 "three months prior to expected commencement of site construction." *Id.* at 37. License condition 46 in SUA-1511, for the Highland project, requires an initial surety instrument for at least $2,233,000.00 to be submitted prior to operation. *Id.*, at 29.

Without explanation, the Staff issued license SUA-1508 to HRI without reviewing HRI's cost-estimates or surety plan. The license does not state the amount of the surety HRI must submit, nor does it set a deadline for submission prior to the commencement of operations. The following table demonstrates the Staff's complete departure from its well-established practice:

Comparison of Surety Histories for Selected NRC-Issued Uranium ISL Licenses following Adoption of 10 CFR Part 40, Appendix A, Criterion 9

Comparison Factor	Crow Butte Project	Highland Project	North Butte Project	Crownpoint Project
NRC License No.	SUA-1534	SUA-1511	SUA-1540	SUA-1508
Date of Initial License	Dec. 29, 1989	Sept. 23, 1987	Dec. 21, 1990	Jan. 5, 1998
Surety Amount Included in Initial License?	Yes	Yes	Yes	No

Surety Amount in Initial License	$4,877,550	$2,233,000	$4,920,705	$0
Effective Date of Surety Amount	"Within 90 days of issuance of this license, the licensee shall submit a surety instrument acceptable to the State of Wyoming and the NRC for an amount not less than $4,877,550." (LC 27)	"Prior to actual operation, Everest Minerals Corporation shall submit a surety instrument acceptable to the State of Wyoming and the NRC for an amount not less than $2,233,000, . . ." (LC 46)	"Three months prior to expected commencement of site construction, the license shall submit a surety instrument acceptable to the State of Wyoming and the NRC in an amount no less than $4,920,705." (LC 35)	"As a prerequisite for operating under this license, the licensee shall submit an NRC-approved surety arrangement to cover the estimated costs of decommissioning, reclamation, and groundwater restoration." (LC 9.5)

B. HRI's License Application Fails to Meet the Atomic Energy Act's Requirements for Protection of Public Health and Safety.

Pre-licensing review of decommissioning cost estimates is necessary to satisfy the NRC's statutory mandate to regulate for the protection of public health and safety requires the Staff to review an applicant's cost estimates and surety plan prior to licensing. The AEA, at 42 U.S.C. § 2099, and NRC regulations at 10 C.F.R. § 40.32(a), forbid the issuance of a license if it would be inimical to the public health and safety. As stated in the preamble to the final rule for Criterion 9, a surety is meant "to protect the public from the possibility of a licensee's inability to perform the required decommissioning and reclamation". Uranium Mill Licensing Requirements, 45 Fed.Reg. 65521, 65526 (October 3, 1980). The importance of compliance with Criterion 9 to ensuring the

protection of the public from the impacts of proposed mining projects is reflected in the comments published with the final rule creating Criterion 9:

> A number of commenters took the position that there is not great sense of urgency for regulations on uranium mill tailings management and mill operations. However, each year new mills are proposed and many millions of tons of tailings are generated at existing mills. As new mills are constructed and more tailings are generated, the options for dealing with tailings disposal become fewer. It is critically important that the siting and design criteria of the regulations be implemented for new facilities so that mistakes of the past are not repeated.

Id., 45 Fed.Reg. at 65523.[7] Here, the HRI license fails to provide crucial measures for public protection required by Criterion 9.

Moreover, the GEIS for Criterion 9 requires: "A plan for decommissioning . . .must be proposed by applicants, and approved by appropriate agencies, before issuance or renewal of licenses. GEIS at 12-5 (emphasis added). This language is found in a section entitled "Supplementary Institutional and Procedural Requirements: Decommissioning, Environmental Review, and Public Participation." GEIS Section 12.2.2. The GEIS specifically provides that: "Opportunity for public hearings should be provided in any mill or mill tailings licensing case." *Id.* Thus, the FEIS' determination that Criterion 9 and other measures are adequate to address the environmental impacts of uranium milling is based on the assumption that decisions on decommissioning financing will be subject to public participation.

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[7] The GEIS recognizes, "The staff considers in situ extraction to be an important and growing component of the uranium recovery industry, and to be capable of significant environmental impacts without adequate control." *Id.*, Comments and Responses, A-67.

Finally, as Dr. Sheehan testified, the proper time to develop and analyze the costs of decommissioning and restoration and the applicant's plans for guaranteeing funding for these costs is at the time of license application. *See* Sheehan Direct Testimony at 6-7. It would be imprudent to issue a license if the decommissioning and restoration costs were uneconomically large, or if the applicant did not have the financial capability to provide the required financial assurance. Sheehan Direct Testimony at 7. Having the product of the analysis available to the applicant ensures that the applicant internalizes the costs and risks it brings to other resource owners. *Id.* This timing requirement prevents valuable resources from being placed at risk from a lack of proper analysis and a lack of necessary guarantees in place.

C. HRI's License Application Fails to Meet the Requirements of 10 C.F.R. § 40.36.

General financial assurance requirements for source materials licensees are established in 10 C.F.R. § 40.36. The rulemaking history of Criterion 9 indicates that the Criterion 9 requirements may only apply to surface wastes. "[I]n situ above ground wastes are treated, both in the text and in the rules to be promulgated on the basis of this document." GEIS, Comments and Responses at A-12 (emphasis added). 10 C.F.R. § 40.36(a) states that it will apply to source materials licenses, unless Criterion 9 applies. Accordingly, in the event Criterion 9 does not apply to mine reclamation, financing for the decommissioning of ISL mines at the Crownpoint Project is governed by 10 C.F.R. § 40.36.

NRC regulations at 10 C.F.R. § 40.36(a) require that at the time a license application is filed, "each applicant for a specific license authorizing the possession and use of more than 100 mCi of source material in a readily dispersable form shall submit a decommissioning funding plan as described in paragraph (d) of this section."[8] As provided in paragraph (d), each decommissioning funding plan must contain a cost estimate for decommissioning; a description of the method of assuring funds for decommissioning from 10 C.F.R. § 40.36(e), including the means for adjusting cost estimates and associated funding levels periodically over the life of the facility; and a certification by the licensee that financial assurance for decommissioning has been provided in the amount of the cost estimate for decommissioning. 10 C.F.R. § 40.36(d).

Contrary to the requirements of 10 C.F.R. § 40.36, HRI failed to submit a decommissioning funding plan at the time of its application. In fact, HRI has submitted no information whatsoever that addresses the criteria for decommissioning funding in § 40.36(d). Accordingly, HRI's license application must be rejected on the ground that it fails to satisfy the clear requirements of the regulations. *See* NRC Order In the Matter of Sequoyah Fuels Corporation General Atomics, (Gore, OK, Site Decontamination and Decommissioning Funding) 58 Fed. Reg. 55,087 (October 25, 1993); Sheehan Direct

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[8] *See also* NUREG-1336, Rev. 1, Section 1.1.4 Standard Format and Content Guide for Financial Assurance Mechanisms Required for Decommissioning Under 10 CFR Parts 30, 40, 70, and 72 (August, 1989), submitted in Intervenors' Presentation, Exhibit 3 ("(n)ew applicants for Category A licenses must submit a DFP at the time of their license application").

Testimony at 6-7.

II. THE INFORMATION SUBMITTED BY HRI IS INADEQUATE TO SATISFY CRITERION 9.

Both HRI and the Staff acknowledge that the Staff has not approved a financial assurance plan for the Crownpoint Project. Staff Response to Petition for Review at 4-5; HRI Response at 5. However, the HRI Response Presentation alleges:

> Although Intervenors complain that HRI has not provided any information regarding estimated decommissioning costs, HRI has, in fact, submitted detailed plans addressing the full cycle economics of the CUP as part of its license application. RAI. Q1-92."

The Staff Response Presentation states it:

> is in the process of reviewing surety materials submitted by HRI. One such item is an HRI letter to Staff (Robert Carlson) dated June 25, 1997, a copy of which is attached hereto (with enclosures) as Staff Exhibit 1. Through an oversight, a copy of this correspondence was mistakenly not included in the HRI Hearing File prepared by the Staff. Another such item is an HRI letter to Staff (Robert Carlson), dated December 11, 1998, a copy of which is attached hereto (with enclosures) as Staff Exhibit 2.
>
> Staff Response at 3, note 4.

The documents referred to by HRI and the Staff, and the whole HRI license application, are entirely deficient under Criterion 9. They are deficient in terms of the scope of the surety proposed, the lack of relevant cost estimates for a third party contractor, lack of contingency cost information, and the lack of explanation to support any of the cost estimates that are provided. HRI's application does not contain a financial assurance plan that supports Commission approval.

A. The Scope of HRI's Financial Documents is Inadequate.

Intervenors argued that HRI's license allows a surety that is inadequate in scope. Intervenors' Presentation at 16-17. LBP-99-13 does not address this concern. Intervenors raised the issue again in the context of the additional information submitted by the NRC Staff in their Reply to Responses to Petition for Review. May 10 Reply at 5; Sheehan Reply Testimony at 1-2.

Under Criterion 9, the required scope of surety liability is clear. According to Criterion 9:

> Regardless of whether reclamation is phased through the life of the operation or takes place at the end of operations, an appropriate portion of surety liability must be retained until final compliance with the reclamation plan is determined.
>
> This will yield a surety that is at least sufficient at all times to cover the costs of decommissioning and reclamation of the areas that are expected to be disturbed before the next license renewal.
>
> 10 C.F.R. Part 40, Appendix A, Criterion 9 (emphasis added).

The rulemaking history of Criterion 9 provide that all licensed activities are within the scope of the required surety, "The surety mechanism covers specific decommissioning and reclamation activities committed to by the operator in the license . . ." 45 Fed.Reg. at 65527(emphasis added).

In addition, the NRC, in practice, has required ISL licensees to provide surety coverage for all licensed activities. In the case of license SUA-1534, the Crow Butte project, the NRC Staff objected to applicant's initial plan which did not incorporate "all

areas licensed for disturbance". File Memorandum from Howard Rose (June 9, 1999), Addendum at 20. After the plan was revised to include the "maximum number of mine units to be constructed in the proposed seven year license," the NRC approved the cost estimate. *Id.* at 22.

HRI's license, SUA-1508, authorizes uranium mining at three sites, Church Rock, Crownpoint and Unit 1 over five years, until January 5, 2003. SUA-1508 at 1, Administrative Condition 9.1. The license authorizes mining, once certain conditions are met, at all sites HRI proposes to operate within five years. HRI's Consolidated Operations Plan Rev. 2.0, Figure 1.4-1 shows production was scheduled to begin at Church Rock in 1998, move to Unit 1 one year later in 1999, and to Crownpoint the following year in 2000. Sheehan Direct Testimony at Exhibit D. At this rate, if HRI were to begin mining in 1999 or 2000, it could still begin operations at all proposed sites before the license expires on January 5, 2003.[9] On September 8, 1998, Mark S. Pelizza, of Uranium Resources, Inc., submitted his "Vision of Sequential CUP Development and Opportunity for Participation" which lists development at Church Rock Section 8 beginning in the year 2000, Church Rock Section 17 and Unit 1 in 2002 and Crownpoint in 2004. HRI's Response to Scheduling Conference Briefs of all Petitioners, Affidavit of Mark Pelizza, Attachment A at 3 (September 9, 1998), a copy of which was submitted in

[9] HRI's production cost per pound is highest at Church Rock, where HRI must start its operations. FEIS at Table 5.1, p. 5-2. It is therefore logical to assume that if HRI has the financial incentive to mine uranium at Church Rock, it will also have the incentive to mine at Crownpoint and Unit 1.

Intervenor's Presentation as Exhibit C to the Sheehan Direct Testimony. Therefore all sites licensed by SUA-1508, including Church Rock Section 17, Unit 1 and Crownpoint should be included in HRI's financial assurance plan.

HRI's license fails to meet the requirements of Criterion 9 because it only requires HRI to establish surety for the "initial wellfields". Administrative Condition 9.5. "Surety shall be maintained [at 9 pore volumes] until the number of pore volumes required to restore the groundwater quality of a production-scale well field has been established by the restoration demonstration described in LC 10.28." *Id.* License Condition 9.5 also states "The licensee shall provide an NRC-approved updated surety before undertaking any planned expansion or operational change which has not been included in the annual surety update." *Id.* Not only does condition 9.5 not require HRI to establish a surety for all area licensed for disturbance, it merely requires a surety for a portion of one area, the Section 8 demonstration. The license, therefore endorses multiple, substantial revisions to the surety, without requiring establishment of a surety for the licensed project prior to operation. This is at odds with Criterion 9 and with the public policy behind surety programs in general. Major revisions to surety requirements are not meant to be accommodated by a mechanism for making minor adjustments in a decommissioning funding plan. *See, e.g. Wisconsin Electric Power Company* (Point Beach Nuclear Power Plant, Unit 2), CLI-73-4, 6 AEC 6 (1973) (mechanism of post-hearing confirmatory findings cannot be used to satisfy initial licensing requirements.)

The financial information referred to by the Staff, information originally submitted to the New Mexico Environment Department ("NMED") for Church Rock Section 8, is also deficient in its scope, for several reasons. Staff Response Presentation Exhibit 1. First, the information refers only to Church Rock Section 8, and thus fails to cover all areas licensed for disturbance, as required by Criterion 9.

Second, the information only covers restoration of the subsurface area and fails to cover surface reclamation and decommissioning. HRI introduces the information as including groundwater remediation, removal and disposal of materials capable of creating leachate, post-restoration stability sampling, and well plugging. Staff Response Presentation, Exhibit 1 at 3-4. Restricting the scope may make sense in the context of the NMED's underground injection control permit, but the NRC also has regulatory concerns over surface radioactivity.

Third, even assuming, for purposes of argument, that a limited surety for Section 8 could be consistent with Criterion 9, the NMED information does not include all areas that would be disturbed by mining at Section 8. Criterion 9 allows NRC to consolidate with sureties required by state agencies if they cover the mill, mill tailings and associated areas. The NRC, in issuing the final rule for Criterion 9, pointed out as a significant feature of Appendix A: "Financial surety arrangements should be established to ensure that sufficient funds are available to cover the costs of decontamination and decommissioning the mill, mill site, and environs and for the reclamation of tailings

areas." 45 Fed.Reg. at 65528. The NMED information does not apply to the Crownpoint mill, which will be required to process uranium from Section 8, nor to the liquid waste disposal areas HRI has proposed to use. Both the mill and liquid waste disposal areas will require surface reclamation.

B. The Content of HRI's Financial Documents is Inadequate.

Criterion 9 sets forth the requirements for cost estimates and a decommissioning funding plan. Those requirements are further documented in the draft Standard Review Plan, Appendix E. Addendum at 11. Appendix E sets forth the cost estimate format to be used by ISL applicants. None of the financial documents referred to by HRI and the Staff provide the information required by Criterion 9 or the information recommended by Appendix E.

Intervenors have previously identified the myriad inadequacies of HRI's license application in this regard. A surety amount has not been identified, complete cost estimates are not provided, the groundwater restoration is set at the unreasonable standard of nine pore volumes, HRI's limited cost estimates do not account for inflation, and the Staff has not accounted for the applicant's poor financial condition, etc. . . *See* Intervenor Presentation at 17-18; Sheehan Direct Testimony at 12, 14-17, 26-32; Intervenors' Reply to Responses to Petition for Review at 4-5; Sheehan Reply Testimony at 1-5.

LBP-99-13 does not address these concerns with one exception. The Presiding Officer rejects Intervenors' argument that the Staff's requirements of 9 pore volumes is

unreasonable, by accusing the Intervenors of attempting "to impugn the motives of the Staff but have not provided any analysis or expert testimony that casts doubt on the Staff estimate." LBP-99-13 at 5-6. The NRC license requirement of establishing a surety on the assumption that nine pore volumes will accomplish groundwater restoration is without a reasonable basis. LBP-99-13's assertion that Intervenors have not presented any evidence to support this concern is incorrect. LBP-99-13, slip.op. at 5-6. The Presiding Officer rashly overlooked the expert testimony and documentary evidence submitted by Intervenors. Dr. Sheehan testifies

> Even 9 pore volumes seriously underestimates the number of pore volumes required for restoration. The Mobile pilot project on section 9 in Church Rock required 16.7 pore volumes and still did not reach complete restoration. FEIS 4-37. At PRI's operations in Wyoming, well field A has taken 21 pore volumes and restoration is not complete. Exhibit E.
>
> Sheehan Direct Testimony at 15 note 6.

Intervenors further developed this argument in their written presentation on groundwater protection. Intervenors Amended Written Presentation in Opposition to Hydro Resources, Inc.'s Application for a Materials License with Respect to: Groundwater Protection, Written Testimony of Dr. Richard Abitz, Exhibit 1 at 48-49, Written Testimony of Dr. William P. Staub Exhibit 2 at 16-22, 40, 43 (January 18, 1999).

HRI's Response to RAI 92 is unrelated to financial assurance. RAI 92 requests that HRI "evaluate and compare the life-cycle profitability and financial feasibility of each alternative, including the proposed project" for the staff to "conduct cost/benefit

analysis of alternatives to the proposed project and to make an economic comparison between the proposed project and alternatives." HRI Response to RAI 92, Addendum at 53. HRI likewise describes its response as a series of "full cycle feasibility studies for each of the three New Mexico projects[,]. . ." and calculates costs for each of four mining alternatives for each of the three sites. *Id.*

While a total Church Rock cost estimate ($10,221,930.00) is listed for the "Restoration and Decommissioning" in HRI's Response to RAI 92, the category provides no detail about the components of this estimate. One category is called "Restoration and Decommissioning." Church Rock Haul Resin Summary, Addendum at 58. HRI's Reponse to RAI 92 is further deficient because it is based on circulating four pore volumes of groundwater, rather than the nine pore volumes required by NRC. *Id.* at 5; License SUA-1508, Administrative Condition 9.5.

The 1997 material HRI submitted to the NMED covers only subsurface restoration costs for Church Rock Section 8, but does not include milling sites, liquid waste disposal, contractor overhead, profit, nor account for inflation. Staff Response, Exhibit 1 at 3-4.

The applications of other licensees are much more detailed, with detailed cost estimates and surety amounts. *See*, letter from S.P. Collins to H. Rose, NRC, (March 7, 1989) (ACN 8905050176), with cost information for the Crowe Butte project, Addendum at 22. *See*, letter from S. P. Morzenti, to H. D. Rose, NRC (March 4, 1987) (ACN

8703240515), transmitting revised Table 3.9 from license application, "Reclamation and Cost Calculation Summary," with cost information for the Highland Project, Addendum at 30. *See*, letter from G. J. Catchpole, to R. Hall, NRC (December 14, 1990) (ACN 9101150269), transmitting revised reclamation/decommissioning bonding section of North Butte Source Material License Application, Addendum at 38.

Appendix E to the DSRP sets forth the cost information the NRC has required of licensees. Appendix E recommends multiple elements and sub-elements be included in cost-information, in order for the NRC to "verify the cost estimates" for a project. DSRP, Appendix E at E-1. Virtually none of this information has been provided by HRI. The following chart lists the cost information elements of Appendix E and tracks how much of that information was provided in the Crow Butte, Highland, and North Butte project applications, and how little is provided in the Crownpoint project application:

Comparison of Draft Standard Review Plan Appendix E Surety Cost Elements with Surety Components of NRC-licensed Uranium ISL Mines

Appendix E Surety Cost Elements	Crow Butte Project (1989)	Highland Project (1987)	North Butte Project (1990)	Crownpoint Project (1996, 1997)
(I) Facility Decommissioning	Y	Y	Y	N
(A) Decontamination of bldgs., equipment;	Y	Y	[unspecified]	[Total costs for "Restoration and Decommission-ing" in HRI response to NRC RAI #92 are aggregated]
dismantling, decontamination	Y	Y	Y	
(B) Dismantling, disposal nonsalvageable bldgs., equip.	Y	Y [unspecified]	Y	
(C) Restoration contam'd areas;	Y	Y	Y	
removal/disposal of byproduct material;	Y	Y	Y	
reclamation/revegetation of disturbed areas	Y	Y	Y	

(II) Groundwater Restoration, Well Plugging	Y	Y	Y	Y (only in '97 NMED info on Section 8)
(A) Restoration method	Y	Y	Y	[unspecified]
(B) Aquifer volume	Y	Y	[unspecified]	[unspecified]
(C) Equipment	Y	Y	Y	Y
(D) Verification sampling	Y	Y	Y	Y
(E) Well plugging/abandonment	Y	Y	Y	Y
(F) Total restoration cost	Y	Y	Y	Y
(III) Radiological Survey and Environmental Monitoring	N [Not specified in surety cost estimates; may be included in decontami-nation cost estimates]	N [Not specified in surety cost estimates; may be included in decontami-nation cost estimates]	Y [No detailed breakdown of "radiation surveys" costs]	N [None of these elements is represented in any of the financial data in HRI's application]
(A) Soil radium				
(B) Smear samples for bldgs., equipment				
(C) Gamma surveys				
(D) Enviro monitoring				
(E) Total cost			Y	
(IV) Project Management Costs and Miscellaneous	Y	Y	Y	[no project mgt. costs specified]
(V) Labor/Equipment Contractor Overhead, Profit	Y	Y - [total labor costs not specified]	Y	N - (contractor overhead/profit) Y - (NMED info on Section 8 has Labor for groundwater restoration/verification sampling)
(VI) Contingency	Y	Y	Y	N

III. THE ADEQUACY OF HRI'S FINANCIAL ASSURANCE PLAN IS RIPE FOR REVIEW.

The Staff alleges "The Staff is in the process of evaluating [HRI's] plan, which was recently amended by HRI in response to comments received from the State of New Mexico. . . . Accordingly, until the Staff completes and documents its evaluation of HRI's surety arrangements, the record on which the Presiding Officer must base his decisions will be incomplete in this regard, and the issue is thus not yet ripe for his review." Staff

Response to Petition for Review at 4-5. HRI goes so far as to argue that "documents submitted in support of the financial assurance plan are altogether irrelevant to this proceeding." HRI Response to Petition for Review at 5. As demonstrated above in Section I, both positions are in error and would undermine the regime developed by the Commission to assure adequate decommissioning funding. The decommissioning plan and cost estimate must be approved before licensing. Moreover, even if establishing a surety can be postponed until operations begin, the amount of the surety is a licensing issue. In addition, financial assurance is not a matter suited to post-hearing resolution. Finally, deferral of this issue will deny Intervenors their right to a meaningful opportunity for hearing.

A. Matters of Financial Assurance are not Appropriate for Post-hearing Resolution.

It is well-established that "the mechanism of post-hearing resolution must not be employed to obviate the basic findings requisite to an operating license — including a reasonable assurance that the facility can be operated safely without endangering the health and safety of the public." *Consolidated Edison Company of New York, Inc. (Indian Point Station*, Unit No. 2), CLI-74-23, 7 AEC 947, 952 (1974). *Indian Point* further cautions that post-hearing resolution "should be employed sparingly and only in clear cases." *Id.* When there are "unresolved aspects" of a licensing review, post-hearing resolution is only suitable for "'minor procedural deficiencies.'" *Long Island Lighting Company* (Shoreham Nuclear Power Station, Unit 1), LBP-83-57, 18 NRC 445,

543-544 (1983) *quoting Consolidated Edison Company of New York*, 7 AEC at 951-952 and note 8 (minor deficiencies in nonsafety-related equipment program can be resolved by the Staff post-hearing, but prior to licensing).

In *Public Service Company of Indiana, Inc.*(Marble Hill Nuclear Generating Station, Units 1 and 2), ALAB-461, 7 NRC 313 (1978), the Appeal Board found that loan guarantee and financial qualifications could not be left over for post-hearing resolution. The Appeal Board stated, "Those are controversial questions in this proceeding, and the Licensing Board's caution in reserving them for its own resolution was entirely appropriate." 7 NRC at 318. Similarly, in this case, there are no unresolved aspects of financial assurance, and the matter of financial assurance itself is not a minor procedural deficiency. Indeed, the issue is highly controversial. The Presiding Officer had no lawful basis to defer it to post-licensing resolution by the Staff. To meet its statutory mandate, the licensing board must hear material licensing issues prior to licensing.

B. Post-hearing Review of HRI's Financial Assurance Plan Violates the Hearing Rights of the Intervenors.

Section 189(a)(1) of the Atomic Energy Act requires that in "any proceeding" for the granting of an operating license to a nuclear facility, "the Commission shall grant a hearing upon the request of any person whose interest may be affected by the proceeding." Atomic Energy Act, 42 U.S.C. § 2239(a)(1)(A). The hearing must offer an opportunity for "*meaningful public participation.*" Union of Concerned Scientists v. NRC, 735 F.2d 1437, 1446, (D.C.Cir. 1984), cert. den. 469 U.S. 1132 (1985), quoting

Bellotti v. NRC, 725 F.2d 1380, 1389 (D.C. Cir. 1983) (emphasis in original). In order to be meaningful, the hearing must be complete in covering the full scope of material issues, and it must be reasonably timed. A meaningful opportunity to be heard means having the opportunity to be heard on "all material factors bearing on the licensing decision raised by the [hearing] requestor. *Id.* at 1443. Postponing the determination of adequacy of HRI's decommissioning funds until after the hearing results in a violation of Intervenors' right to a prior hearing on all issues material to the licensing decision.

The hearing provided under Section 189(a)(1) of the AEA must include an opportunity to be heard on "all material factors bearing on the licensing decision raised by the [hearing] requestor." Union of Concerned Scientists, 735 F.2d at 1443. Determining the adequacy of HRI's decommissioning funds is a material factor bearing on the decision to issue a source material license to HRI.

Unless the information required by Criterion 9 is submitted with the license application and Intervenors have an opportunity to challenge the sufficiency of HRI's compliance with Criterion 9 in the course of this hearing, the license application must be denied. The adequacy of HRI's decommissioning cost estimate and surety arrangement, which must meet specific requirements set forth in Criterion 9, are material licensing issues which cannot lawfully be excluded from the scope of this licensing proceeding. Union of Concerned Scientists, 735 F.2d at 1444-48. Thus, Intervenors are entitled to a hearing on the Applicant's compliance with Criterion 9, before the license can be issued.

CONCLUSION

For the foregoing reasons, the Commission should reverse LBP-99-13, reject HRI's license application because it is inadequate to meet financial assurance requirements and the requirements of the Atomic Energy Act, and revoke HRI's license, SUA-1508 because it was unlawfully issued.

STATEMENT REGARDING REASONS FOR ORAL ARGUMENT

The financial assurance matters before the Commission are complex. Oral argument will aid the Commission in understanding the complicated procedural history in this case and the voluminous hearing record.

Respectfully Submitted,

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August 13, 1999

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION
BEFORE THE COMMISSION

In the Matter of	)	
	)	
HYDRO RESOURCES, INC.	)	Docket No. 40-8968-ML
2929 Coors Road	)	
Suite 101	)	ASLBP No. 95-706-01-ML
Albuquerque, NM 87120	)	
	)	

CERTIFICATE OF SERVICE

I hereby certify that:

On August 13, 1999, I caused to be served copies of the following:

Brief of Intervenors Eastern Navajo Dine Against Uranium Mining and Southwest Research and Information Center on Review of Partial Initial Decision LBP-99-13, Financial Assurance for Decommissioning

upon the following persons by U.S. mail, first class, and in accordance with the requirements of 10 C.F.R. § 2.712. Service was also made via e-mail to the parties marked below by an asterisk. The Addendum to this Brief was served via facsimile to the parties marked below by an asterisk. The envelopes were addressed as follows:

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August 13, 1999,

Johanna Matanich

August 13, 1999

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE COMMISSION

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	)	
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Albuquerque, NM 87120)	)	
	)	

ADDENDUM

BRIEF OF INTERVENORS
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SOUTHWEST RESEARCH AND INFORMATION CENTER

ON REVIEW OF PARTIAL INITIAL DECISION LBP-99-13,
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ADDENDUM
TABLE OF CONTENTS

radon exposure) are dusting from dry surfaces of the tailings disposal area not covered by tailings solution and emissions from yellowcake drying and packaging operations. During operations and prior to closure, radiation doses from radon emissions from surface impoundments of uranium or thorium byproduct materials must be kept as low as is reasonably achievable.

Checks must be made and logged hourly of all parameters (e.g., differential pressures and scrubber water flow rates) that determine the efficiency of yellowcake stack emission control equipment operation. The licensee shall retain each log as a record for three years after the last entry in the log is made. It must be determined whether or not conditions are within a range prescribed to ensure that the equipment is operating consistently near peak efficiency; corrective action must be taken when performance is outside of prescribed ranges. Effluent control devices must be operative at all times during drying and packaging operations and whenever air is exhausting from the yellowcake stack. Drying and packaging operations must terminate when controls are inoperative. When checks indicate the equipment is not operating within the range prescribed for peak efficiency, actions must be taken to restore parameters to the prescribed range. When this cannot be done without shutdown and repairs, drying and packaging operations must cease as soon as practicable. Operations may not be restarted after cessation due to off-normal performance until needed corrective actions have been identified and implemented. All these cessations, corrective actions, and restarts must be reported to the appropriate NRC regional office as indicated in Criterion 8A, in writing, within ten days of the subsequent restart.

To control dusting from tailings, that portion not covered by standing liquids must be wetted or chemically stabilized to prevent or minimize blowing and dusting to the maximum extent reasonably achievable. This requirement may be relaxed if tailings are effectively sheltered from wind, such as may be the case where they are disposed of below grade and the tailings surface is not exposed to wind. Consideration must be given in planning tailings disposal programs to methods which would allow phased covering and reclamation of tailings impoundments because this will help in controlling particulate and radon emissions during operation. To control dusting from diffuse sources, such as tailings and ore pads where automatic controls do not apply, operators shall develop written operating procedures specifying the methods of control which will be utilized.

Milling operations producing or involving thorium byproduct material must be conducted in such a manner as to provide reasonable assurance that the annual dose equivalent does not exceed 25 millirems to the whole body, 75 millirems to the thyroid, and 25 millirems to any other organ of any member of the public as a result of exposures to the planned discharge of radioactive materials, radon-220 and its daughters excepted, to the general environment.

Uranium and thorium byproduct materials must be managed so as to conform to the applicable provisions of title 40 of the Code of Federal Regulations, part 440, "Ore Mining and Dressing Point Source Category: Effluent Limitations Guidelines and New Source Performance Standards, subpart C, Uranium, Radium, and Vanadium Ores Subcategory," as codified on January 1, 1983.

Criterion 8A—Daily inspections of tailings or waste retention systems must be conducted by a qualified engineer or scientist and documented. The licensee shall retain the documentation for each daily inspection as a record for three years after the documentation is made. The appropriate NRC regional office as indicated in appendix D to 10 CFR part 20 of this chapter, or the Director, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC, 20555, must be immediately notified of any failure in a tailings or waste retention system that results in a release of tailings or waste into unrestricted areas, or of any unusual conditions (conditions not contemplated in the design of the retention system) that is not corrected could indicate the potential or lead to failure of the system and result in a release of tailings or waste into unrestricted areas.

II. Financial Criteria

Criterion 9—Financial surety arrangements must be established by each mill operator prior to the commencement of operations to assure that sufficient funds will be available to carry out the decontamination and decommissioning of the mill and site and for the reclamation of any tailings or waste disposal areas. The amount of funds to be ensured by such surety arrangements must be based on Commission-approved cost estimates in a Commission-approved plan for (1) decontamination and decommissioning of mill buildings and the milling site to levels which allow unrestricted use of these areas upon decommissioning, and (2) the reclamation of tailings and/or waste areas in accordance with technical criteria delineated in Section I of this appendix. The licensee shall submit this plan in conjunction with an environmental report that addresses the expected environmental impacts of the milling operation, decommissioning and tailings reclamation, and evaluates alternatives for mitigating these impacts. The surety must also cover the payment of the charge for long-term surveillance and control required

by Criterion 10. In establishing specific surety arrangements, the licensee's cost estimates must take into account total costs that would be incurred if an independent contractor were hired to perform the decommissioning and reclamation work. In order to avoid unnecessary duplication and expense, the Commission may accept financial sureties that have been consolidated with financial or surety arrangements established to meet requirements of other Federal or state agencies and/or local governing bodies for such decommissioning, decontamination, reclamation, and long-term site surveillance and control, provided such arrangements are considered adequate to satisfy these requirements and that the portion of the surety which covers the decommissioning and reclamation of the mill, mill tailings site and associated areas, and the long-term funding charge is clearly identified and committed for use in accomplishing these activities. The licensees's surety mechanism will be reviewed annually by the Commission to assure, that sufficient funds would be available for completion of the reclamation plan if the work had to be performed by an independent contractor. The amount of surety liability should be adjusted to recognize any increases or decreases resulting from inflation, changes in engineering plans, activities performed, and any other conditions affecting costs. Regardless of whether reclamation is phased through the life of the operation or takes place at the end of operations, an appropriate portion of surety liability must be retained until final compliance with the reclamation plan is determined.

This will yield a surety that is at least sufficient at all times to cover the costs of decommissioning and reclamation of the areas that are expected to be disturbed before the next license renewal. The term of the surety mechanism must be open ended, unless it can be demonstrated that another arrangement would provide an equivalent level of assurance. This assurance would be provided with a surety instrument which is written for a specified period of time (e.g., 5 years) yet which must be automatically renewed unless the surety notifies the beneficiary (the Commission or the State regulatory agency) and the principal (the licensee) some reasonable time (e.g., 90 days) prior to the renewal date of their intention not to renew. In such a situation the surety requirement still exists and the licensee would be required to submit an acceptable replacement surety within a brief period of time to allow at least 60 days for the regulatory agency to collect.

Proof of forfeiture must not be necessary to collect the surety so that in the event that the licensee could not provide an acceptable replacement surety within the required time, the surety shall be automatically collected prior to its expiration. The conditions described above would have to be clearly stated on any surety instrument which is not open-ended, and must be agreed to by all parties. Financial surety arrangements generally acceptable to the Commission are:

(a) Surety bonds;

(b) Cash deposits;

(c) Certificates of deposits;

(d) Deposits of government securities;

(e) Irrevocable letters or lines of credit; and

(f) Combinations of the above or such other types of arrangements as may be approved by the Commission. However, self insurance, or any arrangement which essentially constitutes self insurance (e.g., a contract with a State or Federal agency), will not satisfy the surety requirement since this provides no additional assurance other than that which already exists through license requirements.

Criterion 10—A minimum charge of $250,000 (1978 dollars) to cover the costs of long-term surveillance must be paid by each mill operator to the general treasury of the United States or to an appropriate State agency prior to the termination of a uranium or thorium mill license.

If site surveillance or control requirements at a particular site are determined, on the basis of a site-specific evaluation, to be significantly greater than those specified in Criterion 12 (e.g., if fencing is determined to be necessary), variance in funding requirements may be specified by the Commission. In any case, the total charge to cover the costs of long-term surveillance must be such that, with an assumed 1 percent annual real interest rate, the collected funds will yield interest in an amount sufficient to cover the annual costs of site surveillance. The total charge will be adjusted annually prior to actual payment to recognize inflation. The inflation rate to be used is that indicated by the change in the Consumer Price Index published by the U.S. Department of Labor, Bureau of Labor Statistics.

III. Site and Byproduct Material Ownership

Criterion 11—A. These criteria relating to ownership of tailings and their disposal sites become effective on November 8, 1981, and apply to all licenses terminated, issued, or renewed after that date.

B. Any uranium or thorium milling license or tailings license must contain such terms and conditions as the Commission determines necessary to assure that prior to termination of the license, the licensee will comply with ownership requirements of this criterion for sites used for tailings disposal.

C. Title to the byproduct material licensed under this part and land, including any interests therein (other than land owned by the United States or by a State) which is used for the disposal of any such byproduct

and model number of device transferred, and the quantity of depleted uranium contained in the product or device. The report shall be submitted within 30 days after the end of each calendar quarter in which such a product or device is transferred to the generally licensed person. If no transfers have been made to persons generally licensed under § 40.25 during the reporting period, the report shall so indicate;

(2) Report to the responsible Agreement State Agency all transfers of industrial products or devices to persons for use under the general license in the Agreement State's regulation equivalent to § 40.25. Such report shall identify each general licensee by name and address, an individual by name and/or position who may constitute a point of contact between the Agency and the general licensee, the type and model number of device transferred, and the quantity of depleted uranium contained in the product or device. The report shall be submitted within 30 days after the end of each calendar quarter in which such product or device is transferred to the generally licensed person. If no transfers have been made to a particular Agreement State during the reporting period, this information shall be reported to the responsible Agreement State Agency;

(3) Keep records showing the name, address, and a point of contact for each general license to whom he or she transfers depleted uranium in industrial products or devices for use pursuant to the general license provided in § 40.25 or equivalent regulations of an Agreement State. The records must be retained for three years from the date of transfer and must show the date of each transfer, the quantity of depleted uranium in each product or device transferred, and compliance with the report requirements of this section.

(f) Licensees required to submit emergency plans by § 40.31(i) shall follow the emergency plan approved by the Commission. The licensee may change the plan without Commission approval if the changes do not decrease the effectiveness of the plan. The licensee shall furnish the change to the Director of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington, DC 20555 and to affected offsite response organizations within six months after the change is made. Proposed changes that decrease the effectiveness of the approved emergency plan may not be implemented without application to and prior approval by the Commission.

[41 FR 53332, Dec. 6, 1976, as amended at 43 FR 6924, Feb. 17, 1978; 52 FR 31611, Aug. 21, 1987; 53 FR 19248, May 27, 1988; 54 FR 14062, Apr. 7, 1989]

§ 40.36 Financial assurance and recordkeeping for decommissioning.

Except for licenses authorizing the receipt, possession, and use of source material for uranium or thorium milling, or byproduct material at sites formerly associated with such milling, for which financial assurance requirements are set forth in appendix A of this part, criteria for providing financial assurance for decommissioning are as follows:

(a) Each applicant for a specific license authorizing the possession and use of more than 100 mCi of source material in a readily dispersible form shall submit a decommissioning funding plan as described in paragraph (d) of this section.

(b) Each applicant for a specific license authorizing possession and use of quantities of source material greater than 10 mCi but less than or equal to 100 mCi in a readily dispersible form shall either—

(1) Submit a decommissioning funding plan as described in paragraph (d) of this section; or

(2) Submit a certification that financial assurance for decommissioning has been provided in the amount of $150,000 using one of the methods described in paragraph (e) of this section. For an applicant, this certification may state that the appropriate assurance will be obtained after the application has been approved and the license issued but before the receipt of licensed material. If the applicant defers execution of the financial instrument until after the license has been issued, a signed original of the financial instrument obtained to satisfy the requirements of paragraph (e) of this section must be submitted to NRC prior to receipt of licensed material. If the applicant does not defer execution of the financial instrument, the

applicant shall submit to NRC, as part of the certification, a signed original of the financial instrument obtained to satisfy the requirements of paragraph (e) of this section.

(c)(1) Each holder of a specific license issued on or after July 27, 1990, which is covered by paragraph (a) or (b) of this section, shall provide financial assurance for decommissioning in accordance with the criteria set forth in this section.

(2) Each holder of a specific license issued before July 27, 1990, and of a type described in paragraph (a) of this section shall submit, on or before July 27, 1990, a decommissioning funding plan as described in paragraph (d) of this section or a certification of financial assurance for decommissioning in an amount at least equal to $750,000 in accordance with the criteria set forth in this section. If the licensee submits the certification of financial assurance rather than a decommissioning funding plan, the licensee shall include a decommissioning funding plan in any application for license renewal.

(3) Each holder of a specific license issued before July 27, 1990, and of a type described in paragraph (b) of this section shall submit, on or before July 27, 1990, a decommissioning funding plan, as described in paragraph (d) of this section, or a certification of financial assurance for decommissioning in accordance with the criteria set forth in this section.

(4) Any licensee who has submitted an application before July 27, 1990, for renewal of license in accordance with § 40.43 shall provide financial assurance for decommissioning in accordance with paragraphs (a) and (b) of this section. This assurance must be submitted when this rule becomes effective November 24, 1995.

(d) Each decommissioning funding plan must contain a cost estimate for decommissioning and a description of the method of assuring funds for decommissioning from paragraph (e) of this section, including means for adjusting cost estimates and associated funding levels periodically over the life of the facility. The decommissioning funding plan must also contain a certification by the licensee that financial assurance for decommissioning has been provided in the amount of the cost estimate for decommissioning and a signed original of the financial instrument obtained to satisfy the requirements of paragraph (e) of this section.

(e) Financial assurance for decommissioning must be provided by one or more of the following methods:

(1) *Prepayment.* Prepayment is the deposit prior to the start of operation into an account segregated from licensee assets and outside the licensee's administrative control of cash or liquid assets such that the amount of funds would be sufficient to pay decommissioning costs. Prepayment may be in the form of a trust, escrow account, government fund, certificate of deposit, or deposit of government securities.

(2) *A surety method, insurance, or other guarantee method.* These methods guarantee that decommissioning costs will be paid. A surety method may be in the form of a surety bond, letter of credit, or line of credit. A parent company guarantee of funds for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix A to part 30. A parent company guarantee may not be used in combination with other financial methods to satisfy the requirements of this section. For commercial corporations that issue bonds, a guarantee of funds by the applicant or licensee for decommissioning costs based on a financial test may be used if the guarantee and test are as contained in appendix C to part 30. For commercial companies that do not issue bonds, a guarantee of funds by the applicant or licensee for decommissioning costs may be used if the guarantee and test are as contained in appendix D to part 30. For nonprofit entities, such as colleges, universities, and nonprofit hospitals, a guarantee of funds by the applicant or licensee may be used if the guarantee and test are as contained in appendix E to part 30. A guarantee by the applicant or licensee may not be used in combination with any other financial methods used to satisfy the requirements of this section or in any situation where the applicant or licensee has a parent company holding majority control of the voting stock of

the company. Any surety method or insurance used to provide financial assurance for decommissioning must contain the following conditions:

(i) The surety method or insurance must be open-ended or, if written for a specified term, such as five years, must be renewed automatically unless 90 days or more prior to the renewal date, the issuer notifies the Commission, the beneficiary, and the licensee of its intention not to renew. The surety method or insurance must also provide that the full face amount be paid to the beneficiary automatically prior to the expiration without proof of forfeiture if the licensee fails to provide a replacement acceptable to the Commission within 30 days after receipt of notification of cancellation.

(ii) The surety method or insurance must be payable to a trust established for decommissioning costs. The trustee and trust must be acceptable to the Commission. An acceptable trustee includes an appropriate State or Federal government agency or an entity which has the authority to act as a trustee and whose trust operations are regulated and examined by a Federal or State agency.

(iii) The surety method or insurance must remain in effect until the Commission has terminated the license.

(3) An external sinking fund in which deposits are made at least annually, coupled with a surety method or insurance, the value of which may decrease by the amount being accumulated in the sinking fund. An external sinking fund is a fund established and maintained by setting aside funds periodically in an account segregated from licensee assets and outside the licensee's administrative control in which the total amount of funds would be sufficient to pay decommissioning costs at the time termination of operation is expected. An external sinking fund may be in the form of a trust, escrow account, government fund, certificate of deposit, or deposit of government securities. The surety or insurance provision must be as stated in paragraph (e)(2) of this section.

(4) In the case of Federal, State, or local government licensees, a statement of intent containing a cost estimate for decommissioning or an amount based on paragraph (b) of this section, and indicating that funds for decommissioning will be obtained when necessary.

(5) When a government entity is assuming custody and ownership of a site, an arrangement that is deemed acceptable by such government entity.

(f) Each person licensed under this part shall keep records of information important to the decommissioning of a facility in an identified location until the site is released for unrestricted use. Before licensed activities are transferred or assigned in accordance with § 40.41(b) licensees shall transfer all records described in this paragraph to the new licensee. In this case, the new licensee will be responsible for maintaining these records until the license is terminated. If records important to the decommissioning of a facility are kept for other purposes, reference to these records and their locations may be used. Information the Commission considers important to decommissioning consists of—

(1) Records of spills or other unusual occurrences involving the spread of contamination in and around the facility, equipment, or site. These records may be limited to instances when contamination remains after any cleanup procedures or when there is reasonable likelihood that contaminants may have spread to inaccessible areas as in the case of possible seepage into porous materials such as concrete. These records must include any known information on identification of involved nuclides, quantities, forms, and concentrations.

(2) As-built drawings and modifications of structures and equipment in restricted areas where radioactive materials are used and/or stored, and of locations of possible inaccessible contamination such as buried pipes which may be subject to contamination. If required drawings are referenced, each relevant document need not be indexed individually. If drawings are not available, the licensee shall substitute appropriate records of available information concerning these areas and locations.

(3) Except for areas containing depleted uranium used only for shielding or as penetrators in unused munitions,

a list contained in a single document and updated every 2 years, of the following:

(i) All areas designated and formerly designated as restricted areas as defined under 10 CFR 20.1003;

(ii) All areas outside of restricted areas that require documentation under §40.36(f)(1);

(iii) All areas outside of restricted areas where current and previous wastes have been buried as documented under 10 CFR 20.2108; and

(iv) All areas outside of restricted areas that contain material such that, if the license expired, the licensee would be required to either decontaminate the area to meet the criteria for decommissioning in 10 CFR part 20, subpart E, or apply for approval for disposal under 10 CFR 20.2002.

(4) Records of the cost estimate performed for the decommissioning funding plan or of the amount certified for decommissioning, and records of the funding method used for assuring funds if either a funding plan or certification is used.

[53 FR 24047, June 27, 1988, as amended at 58 FR 39633, July 26, 1993; 58 FR 67661, Dec. 22, 1993; 58 FR 68731, Dec. 29, 1993; 59 FR 1618, Jan. 12, 1994; 60 FR 38238, July 26, 1995; 61 FR 24674, May 16, 1996; 62 FR 39090, July 21, 1997; 63 FR 29543, June 1, 1998]

§40.38 Ineligibility of certain applicants.

A license may not be issued to the Corporation if the Commission determines that:

(a) The Corporation is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government; or

(b) The issuance of such a license would be inimical to—

(1) The common defense and security of the United States; or

(2) The maintenance of a reliable and economical domestic source of enrichment services.

[62 FR 6669, Feb. 12, 1997]

LICENSES

§40.41 Terms and conditions of licenses.

(a) Each license issued pursuant to the regulations in this part shall be subject to all the provisions of the act, now or hereafter in effect, and to all rules, regulations and orders of the Commission.

(b) Neither the license nor any right under the license shall be assigned or otherwise transferred in violation of the provisions of the Act.

(c) Each person licensed by the Commission pursuant to the regulations in this part shall confine his possession and use of source or byproduct material to the locations and purposes authorized in the license. Except as otherwise provided in the license, a license issued pursuant to the regulations in this part shall carry with it the right to receive, possess, and use source or byproduct material. Preparation for shipment and transport of source or byproduct material shall be in accordance with the provisions of part 71 of this chapter.

(d) Each license issued pursuant to the regulations in this part shall be deemed to contain the provisions set forth in sections 183b.–d., of the Act, whether or not said provisions are expressly set forth in the license.

(e) The Commission may incorporate in any license at the time of issuance, or thereafter, by appropriate rule, regulation or order, such additional requirements and conditions with respect to the licensee's receipt, possession, use, and transfer of source or byproduct material as it deems appropriate or necessary in order to:

(1) Promote the common defense and security;

(2) Protect health or to minimize danger of life or property;

(3) Protect restricted data;

(4) Require such reports and the keeping of such records, and to provide for such inspections of activities under the license as may be necessary or appropriate to effectuate the purposes of the act and regulations thereunder.

(f)(1) Each licensee shall notify the appropriate NRC Regional Administrator, in writing, immediately following the filing of a voluntary or involuntary petition for bankruptcy under any chapter of title 11 (Bankruptcy) of the United States Code by or against:

(i) The licensee;

NUREG-1569

DRAFT
STANDARD REVIEW PLAN
for *In Situ* Leach Uranium Extraction License Applications

Manuscript Completed: September 1997
Date Published: October 1997

Division of Waste Management
Office of Nuclear Material Safety and Safeguards
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

necessary to comply with these standards; and 10 CFR 51.45(c), which requires the applicant to provide sufficient data for the Commission to conduct an independent analysis. The related reviews of the 10 CFR Part 51 environmental protection regulations for domestic licensing and related regulatory functions for plans and schedules for groundwater restoration in accordance with SRP sections 5.0, Operations; and 7.0, Environmental Effects; are addressed elsewhere in this TER.

6.4.5 References

Berger, J.D. 1992. *Manual for Conducting Radiological Surveys in Support of License Termination.* Draft report for comment, NUREG/CR-5849. Washington, DC: Nuclear Regulatory Commission.

Nuclear Regulatory Commission, 1981, Disposal or On-site Storage of Thorium or Uranium Wastes From Past Operations, *Federal Register*, vol. 46, p. 52061, October 23, 1981.

6.5 FINANCIAL ASSESSMENT FOR GROUNDWATER RESTORATION, DECOMMISSIONING, RECLAMATION, WASTE DISPOSAL, AND MONITORING

6.5.1 Areas of Review

The staff shall review financial assessments provided by the applicant for the costs of groundwater restoration (section 6.1); reclamation (section 6.2); and decommissioning, waste disposal, and monitoring (section 6.4). These assessments may be provided in the form of a narrative or as an appendix. The staff shall review provisions for a financial surety similar to those contained in criterion 9 of 10 CFR Part 40, appendix A.

6.5.2 Review Procedures

The staff shall review the financial surety assessment provided by the applicant to verify that the activities incorporated in the financial assessment are consistent with the activities proposed in the application. In addition, the reviewer shall verify that the activities proposed in the application are included in the financial assessments. The purpose of the financial surety is to provide sufficient resources for completion of reclamation of the facility including building decommissioning and well-field restoration and soil decommissioning by an independent contractor if necessary.

The reviewer shall determine whether the assumptions for the financial surety analysis are consistent with what is known about the site (SRP section 2.0) and the design and operations of the facility and its effluent control system (SRP sections 3.0, 4.0, and 5.0). To the extent possible, the applicant should base these assumptions on experience from generally accepted industry practices, from R&D activities at the site, or from previous operating experience in the case of a license renewal. The values used in the analysis should be based on current dollars (or adjusted for inflation) and reasonable values for the costs of various activities. The reviewer shall also examine the type of financial instrument proposed for the surety to ensure that it is in accordance with the requirements of 10 CFR Part 40, appendix A, criterion 9.

For license renewals and amendment applications, appendix A to this standard review plan (SRP) provides guidance for examining facility operations and the approach that should be used in evaluating amendments and renewal applications.

6.5.3 Acceptance Criteria

The financial assessment for groundwater restoration, decommissioning, reclamation, waste disposal, and monitoring is acceptable if it meets the following criteria:

(1) The bases for establishing a financial surety are provided in accordance with those found in 10 CFR Part 40, appendix A, criterion 9. Surety for well fields is usually established as they go into production. Once accepted, the surety will be reviewed annually by NRC to assure that sufficient funds would be available for completion of the reclamation plan by an independent contractor. Detailed guidance on reviewing financial assessments for ISL operations is found in appendix E of this SRP.

(2) All activities included in the financial analysis are activities that are included either in the reclamation plan or in sections 6.1 through 6.4.

(3) All activities included either in the reclamation plan or in sections 6.1 through 6.4 are included in the financial analysis.

(4) The assumptions used for the financial surety analysis are consistent with what is known about the site (SRP section 2.0) and the design and operations of the facility and its effluent control system (SRP sections 3.0, 4.0 and 5.0). To the extent possible, the applicant has based these assumptions on experience from generally accepted industry practices, R&D at the site, or previous operating experience in the case of a license renewal.

(5) The applicant commits to funding the approved financial surety through one of the mechanisms described in Regulatory Guide 3.66 (Nuclear Regulatory Commmission, 1990).

6.5.4 Evaluation Findings

If the staff's review, as described in this section, results in the acceptance of the financial assessment for groundwater restoration, decommissioning, reclamation, waste disposal, and monitoring, the following conclusions may be presented in the TER.

The NRC has completed its review of the procedures for conducting financial assessment for groundwater restoration, decommissioning, reclamation, waste disposal, and monitoring proposed for use at the _____ISL facility. This review included an evaluation of the methods that will be used to develop the procedures using the review procedures in SRP section 6.5.2 and the acceptance criteria outlined in SRP section 6.5.3.

The applicant has established an acceptable financial surety based on the requirements in 10 CFR Part 40, appendix A, criterion 9. The applicant has assured that sufficient funds would be available for completion of the reclamation plan by an independent contractor. The applicant has included in the financial analyses all the activities in the reclamation plan or in sections 6.1 through 6.4 of the SRP. The applicant has based the assumptions for financial surety analysis on site conditions including experiences with generally accepted industry practices, R&D at the site, and previous operating experience (in the case of a license renewal). The values used in the financial surety analysis are based on current dollars (or adjusted for inflation) and reasonable costs for the required reclamation activities are defined. The financial instrument proposed is a (i) surety bond, (ii) cash deposit, (iii) certificate of deposit, (iv) deposit of a government security, (v) irrevocable letters or lines of credit, or (vi) combinations of the above that meet the total surety requirements (select appropriate description) and is acceptable.

Based on the information provided in the application and the detailed review conducted of the procedures for conducting the financial assessment for groundwater restoration, decommissioning, reclamation, waste disposal, and monitoring for the _____ ISL facility, the NRC staff has concluded that the procedures are acceptable and are in compliance with 10 CFR Part 40, criterion 9, which requires financial surety arrangements be established by each operator. The related reviews of the 10 CFR Part 51 environmental protection regulations for domestic licensing and related regulatory functions for plans and schedules for groundwater restoration in accordance with SRP sections 5.0, Operations; and 7.0, Environmental Effects; are addressed elsewhere in this TER.

6.5.5 References

Nuclear Regulatory Commission, 1990, Standard Format and Content of Financial Assurance Mechanisms Required for Decommissioning Under 10 CFR Parts 30, 40, 70, and 72. Regulatory Guide 3.66, Washington DC: Nuclear Regulatory Commission, Office of Nuclear Regulatory Research.

APPENDIX E
RECOMMENDED OUTLINE FOR SITE-SPECIFIC *IN SITU* LEACH FACILITY RECLAMATION AND STABILIZATION COST ESTIMATES

As required under Criteria 9 and 10 of 10 CFR Part 40, appendix A, the licensee shall supply sufficient information for the Nuclear Regulatory Commission (NRC) to verify that the amount of coverage provided by the financial assurance accounts for all necessary activities required under the license to allow the license to be terminated. Cost estimates for the following activities (where applicable) should be submitted to NRC with the initial license application or reclamation plan and should be updated annually as specified in the license. Cost estimates must be calculated an the basis of completion of all activities by a third party. Unit costs, calculations, references, assumptions and equipment and operator efficiencies, etc., must be provided.

The detailed cost information necessary to verify the cost estimates for the above categories of closure work is described in the following recommended outline.

(I) FACILITY DECOMMISSIONING

This includes dismantling, decontamination and disposal of all structures and equipment. This may be accomplished in two phases. In the first phase, only the equipment not used for groundwater restoration (including the stability monitoring period) is removed. Well plugging and removal of the remaining equipment would be performed in a second phase, after the approved completion of groundwater restoration. The buildings used for the *in situ* operations may be decontaminated and released for unrestricted use.

(A) Salvageable building and equipment decontamination (list). For each building or piece of equipment listed, the following data should be provided:

(1) Labor for dismantling and decontamination

(a) Person-hours and categories of labor

(b) Average hourly wage for each category

(c) Total labor cost (benefits, insurance, etc., and all labor overhead must be included here or calculated on the basis of total project labor)

(2) Equipment and material for dismantling and decontamination:

(a) Itemization of equipment and material to be used for decontamination

(b) Itemized cost for material and equipment cost per hour listed in (a) above (equipment costs must include hourly operating, ownership, and overhead expenses)

(c) Operating hours for each piece of equipment

(d) Total equipment and material cost.

(B) Nonsalvageable building and equipment disposal

(1) List of major categories of building and equipment to be disposed of and their corresponding quantities:

(a) Structures (list each major) (tons of material and building volume cubic feet)

(b) Foundation concrete (cubic yards)

(c) Process equipment (tons)

(d) Piping and insulation (lump sum)

(e) Electrical and instrumentation (lump sum)

(2) Unit cost of disposal for each item above (include equipment, labor, material, transportation, and disposal costs)

(3) List and state how each chemical solution within the mill area will be disposed of along with the associated cost of disposal

(4) Total cost

(C) Restoration of contaminated areas (ore storage pad, access roads, process area, affected groundwater, evaporation pond residues, etc.)

Removal and Disposal of 11(e)2 byproduct material—In 10 CFR 40, appendix A, criterion it required that these materials are to be transported and disposed at a licensed tailings area or licensed disposal site. The quantity of material to be removed and the distance to the disposal site and the fees charged by the receiving facility are important considerations in determining the costs of disposal.

Reclamation—This entails recontouring the well fields and evaporation ponds and placing top soil or other materials acceptable to the NRC. This may also include revegetation.

(1) Removal:

(a) Area, depth, and quantity of material to be removed (area, feet, and cubic yard—or size of liner if appropriate)

(b) Unit cost (include excavation, loading, transportation, and deposition)

(c) Total cost (equipment and labor)

(2) Revegetation:

(a) Area to be revegetated (acre)

(b) Unit cost (include fill material replacing topsoil, and revegetation cost)

(c) Total cost (equipment, labor, and materials)

(II) GROUNDWATER RESTORATION AND WELL PLUGGING

In most cases, groundwater restoration consists of groundwater sweeping and water treatment with partial reinjection. The water treatment equipment used during the uranium recovery phase of the operation is generally suitable for the restoration phase. The capital cost of this equipment is usually absorbed during the initial stages of the operation leaving only the costs of operation, maintenance, and replacement filters for the restoration phase. However, if additional equipment will be required for restoration, associated costs should be detailed here. Replacement costs of some water treatment equipment may need to be included in the surety if the equipment used for restoration is near the end of it's serviceable life.

(A) Method of restoration

(B) Volume of aquifer required to be restored, area and thickness of aquifer, number of required pumping cycles, and cycling time

(C) Equipment associated with aquifer restoration (e.g., reverse osmosis unit)

(D) Verification sample analysis

(1) Number of samples

(2) Unit cost for sample collection and analysis (per sample)

(3) Total cost for verification sample analysis

(E) Well plugging

(1) Number of drill holes to be plugged

(2) Depth and size of each drill hole

(3) Material to he used for plugging including acquisition, transportation, and plugging

(4) Total cost for well plugging

(F) Total cost for groundwater restoration

(III) RADIOLOGICAL SURVEY AND ENVIRONMENTAL MONITORING

Radiological Survey—Surveys and soil samples for radium in areas to be released for restricted use. Soils around the well fields, evaporation ponds, and process buildings should be analyzed for radium content. A gamma survey of all areas should be made prior to release for unrestricted use. All equipment released for unrestricted use should be surveyed and records maintained.

(A) Soil samples for radium

(B) Decommissioning equipment and building smear samples

(C) Gamma survey

(D) Environmental monitoring

Costs of labor, materials, and analysis for continuation of environmental monitoring program throughout reclamation.

(E) Total cost

(1) Number of each kind sample listed above

(2) Unit cost for sample and analysis (price per sample)

(3) Total cost for radiological survey

(IV) PROJECT MANAGEMENT COSTS AND MISCELLANEOUS

Itemize estimated costs associated with project management, engineering changes. mobilization costs, legal expenses, power costs during reclamation, quality control, radiological safety costs, etc.

(V) LABOR AND EQUIPMENT OVERHEAD, CONTRACTOR PROFIT

Overhead costs for labor and equipment and contractor profit may be calculated as separate items or loaded into hourly rates. If included in hourly rates, the unit costs must identify the percentages applied for each area.

(VI) CONTINGENCY

The licensee should include a contingency amount to the total cost estimate for the final site closure. The staff currently considers a 15 percent contingency to be an acceptable minimum amount.

(VIII) ADJUSTMENTS TO SURETY AMOUNTS

The licensee is required by 10 CFR Part 40, appendix A, criteria 9 to adjust cost estimates annually to account for inflation and changes in reclamation plans. The submission should be in the form of a request for amendment to the license.

(A) Adjustments for inflation

The licensee should submit a revised surety incorporating adjustments to the cost estimates for inflation 90 days prior to each anniversary of the date on which the first reclamation plan and cost estimate was approved. The adjustment should be made using the inflation rule indicated by the change in the Urban Consumer Price Index published by the U.S. Department of Labor, Bureau of Labor Statistics.

(B) Changes in Plans

(1) Changes in the process such as size or method of operation.

(2) Licensee initiated changes in reclamation plans or reclamation/decommissioning activities performed.

(3) Adjustments to reclamation plans required by the NRC.

(4) Proposed revisions to reclamation plans must be thoroughly documented and cost estimates and the basis for cost estimates detailed for NRC review and approval. Where a licensee is authorized by the NRC to secure a surety arrangement with the state, no reduction to the surety amount shall be initiated without prior NRC approval. Copies of all correspondence relating to the surety between the licensee and the state shall be provided to the NRC. If authorized by the NRC to maintain a surety with the state as the beneficiary, it is the responsibility of the licensee to provide the NRC with verification of same; ensure that the agreement with the state specifically identifies the financial surety's application, *in situ* leach (ISL) facility, and decommissioning/reclamation requirements; and transfer the long-term surveillance and control fee to the U.S. Department of the Treasury prior to license termination.

All costs (unit and total) are to be estimated on the basis of independent contractor costs (include overhead and profit in unit costs or as 3 percentage of total). Equipment owned by the licensee and the availability of licensee staff should not be considered in the estimate to reduce cost calculations. All costs should be based on current year dollars. Credit for salvage value is generally not acceptable on the estimated costs.

The NRC staff review may include a comparison of unit cost estimates with standard construction cost guides (e.g.. Dodge Guide, Data Quest) and discussions with appropriate state or local authorities (highway cost construction). The licensee should provide supporting information or the basis for selection of the unit cost figures used in estimates.

NRC Form 374 (5-84) U.S. NUCLEAR REGULATORY COMMISSION PAGE 1 OF 9 PAGES

MATERIALS LICENSE

Pursuant to the Atomic Energy Act of 1954, as amended, the Energy Reorganization Act of 1974 (Public Law 93-438), and Title 10, Code of Federal Regulations, Chapter I, Parts 30, 31, 32, 33, 34, 35, 40 and 70, and in reliance on statements and representations heretofore made by the licensee, a license is hereby issued authorizing the licensee to receive, acquire, possess, and transfer byproduct, source, and special nuclear material designated below; to use such material for the purpose(s) and at the place(s) designated below; to deliver or transfer such material to persons authorized to receive it in accordance with the regulations of the applicable Part(s). This license shall be deemed to contain the conditions specified in Section 183 of the Atomic Energy Act of 1954, as amended, and is subject to all applicable rules, regulations and orders of the Nuclear Regulatory Commission now or hereafter in effect and to any conditions specified below.

Licensee		
1. Ferret Exploration Company of Nebraska, Inc. 2. 216 Sixteenth Street Mall, Suite 810 Denver, Colorado 80202	3. License number	SUA-1534
	4. Expiration date	January 1, 1996
	5. Docket or Reference No.	40-8943

6. Byproduct, source, and/or special nuclear material	7. Chemical and/or physical form	8. Maximum amount that licensee may possess at any one time under this license
a. Natural Uranium b. Byproduct material as defined in §11e(2) of Atomic Energy Act of 1954, as amended.	Any	a. 454,545 kg b. Quantity generated under operations authorized by this license.

9. Authorized place of use shall be the licensee's Crow Butte facilities in Dawes County, Nebraska.

10. For use in accordance with statements, descriptions and representations contained in Sections 3.0, 4.0, 5.0 and 6.0 of the licensee's application submitted by cover letter dated October 7, 1988, as revised by submittals dated December 14, 1987; January 22, 1988; March 28, 1988; May 17, 1988; April 27, 1988, and July 27, 1988; as well as letters dated October 10, 1989 and October 26, 1989.

Notwithstanding the above, the following conditions shall override any conflicting statements contained in the licensee's application and supplements.

11. The licensee is prohibited from commencing lixiviant injection or generating byproduct materials until such time as written NRC concurrence is received on their proposed waste disposal facility.

12. The annual throughput shall not exceed a flow rate of 2500 gallons per minute, exclusive of restoration flow.

13. The licensee shall not possess more than 454,545 kilograms of barreled U_3O_8 at one time.

14. The Crow Butte production rate shall not exceed 1,000,000 pounds of U_3O_8 per year.

MATERIALS LICENSE
SUPPLEMENTARY SHEET

License Number: SUA-1534
Docket or Reference number: 40-8943

25. The licensee shall perform and document weekly visual inspections of the evaporation pond embankments, fences and liners, as well as measurements of pond freeboard and checks of the leak detection system. Any time six (6) inches or more of fluid is in the leak detection system standpipes, it shall be analyzed for conductivity, chloride, alkalinity, sodium and sulfate. Should analyses indicate that the pond is leaking, the NRC, Uranium Recovery Field Office, shall be notified by telephone within forty-eight (48) hours of verification and the pond level lowered by transferring its contents into an alternate cell. Standpipe water quality samples shall be analyzed for the above parameters once every seven (7) days during the leak period and once every seven (7) days for at least two (2) weeks following repairs.

A written report shall be filed with the NRC, Uranium Recovery Field Office, within thirty (30) days of first notifying the NRC that a leak exists. This report shall include analytical data and describe the mitigative action and the results of that action.

26. The licensee shall maintain an area within the restricted area boundary for storage of contaminated materials prior to their disposal. All contaminated wastes and evaporation pond residues shall be disposed at a licensed radioactive waste disposal site.

27. The licensee shall maintain an NRC-approved financial surety arrangement, consistent with 10 CFR 40, Appendix A, Criterion 9, adequate to cover the estimated costs, if accomplished by a third party, for completion of the NRC-approved site closure plan including: above ground decommissioning and decontamination, the cost of offsite disposal of radioactive solid process or evaporation pond residues, soil and water analyses and ground-water restoration as warranted. Within three (3) months of NRC approval of a revised closure plan and cost estimate, the licensee shall submit for NRC review and approval, a proposed revision to the financial surety arrangement if estimated costs in the newly approved site closure plan exceed the amount covered in the existing financial surety. The revised surety shall then be in effect within three (3) months of written NRC approval. Annual updates to the surety amount, required by 10 CFR Part 40, Appendix A, Criterion 9, shall be provided to the NRC at least three (3) months prior to the anniversary of the effective date of the existing surety instrument. If the NRC has not approved a proposed revision 30 days prior to the expiration date of the existing surety arrangement, the licensee shall extend the existing arrangement, prior to expiration, for 1 year.

Along with each proposed revision or annual update, the licensee shall submit supporting documentation showing a breakdown of the costs and basis for the cost estimates with adjustments for inflation, maintenance of a minimum 15 percent contingency changes in engineering plans, activities performed and any other conditions affecting estimated costs for site closure. When the NRC authorizes the surety instrument to be held by the State of Nebraska, the licensee shall also provide the NRC with copies of surety related correspondence submitted to the State, a copy of the State's surety review and the final approved surety arrangement on an annual basis. The licensee must also ensure that the surety.

MATERIALS LICENSE
SUPPLEMENTARY SHEET

License number: SUA-1534
Docket or Reference number: 40-8943

where authorized to be held by the State of Nebraska, expressly identifies the NRC related portion of the surety and covers the above ground decommissioning and decontamination, the cost of offsite disposal, soil and water sample analyses and ground-water restoration associated with the site. The basis for the cost estimate is the NRC-approved site closure plan or NRC-approved revisions to the plan.

Within 90 days of issuance of this license, the licensee shall submit a surety instrument acceptable to the State of Nebraska and the NRC, Uranium Recovery Field Office, for an amount not less than $4,877,550. This surety shall be written in favor of the State or the NRC for the purpose of complying with 10 CFR Part 40, Appendix A, Criterion 9, until a replacement is authorized by both the State and the NRC. The licensee shall maintain the existing approved surety until a replacement is authorized by the NRC. Annual updates and reclamation/decommissioning plan cost estimates should follow the outline in the attachment to this license entitled, "Recommended Outline for Site Specific Reclamation and Stabilization Cost Estimates." For the purposes of NRC's annual review, the licensee's anniversary date is designated as January 1 of each successive year. The annual update should be received by the NRC 90 days prior to the anniversary date.

28. In addition to the inspection and audit program described in Section 5.3 of the application, dated October 7, 1987, the Health Physics Technician (HPT) or designate shall document a daily walkthrough of the facility to determine if radiation control practices are being implemented.

29. The licensee shall submit to the NRC, Uranium Recovery Field Office, a copy of the ALARA report as specified in Section 4.7 of the application dated October 7, 1987, within two (2) months of the end of the reporting period. The report shall also include a summary of the daily walkthrough inspections.

30. The licensee shall submit to the NRC, Uranium Recovery Field Office, particulate and radon sampling locations as well as designated eating areas at least two (2) months prior to beginning uranium recovery operations. The locations, as a minimum, shall include the drying and packaging area and all worker occupied stations associated with the uranium recovery process. Radon daughters shall be sampled weekly, and particulates shall be sampled weekly in the dry/pack areas and monthly in the process areas.

31. In addition to the bioassay program discussed in Section 5.7.5 of the application, dated October 7, 1987, the licensee shall comply with the following:

A. Anytime an action level of 15 ug/l uranium for urinalysis is reached or exceeded, the licensee shall document the corrective actions which have been performed in accordance with Revision 1 of Regulatory Guide 8.22, dated January 1987. This documentation shall be submitted to the NRC, Uranium Recovery Field Office, as part of the semiannual report required by 10 CFR Part 40.65.

UNITED STATES

NUCLEAR REGULATORY COMMISSION

REGION IV

URANIUM RECOVERY FIELD OFFICE
BOX 25325
DENVER, COLORADO 80225

JUN 9 1989

URFO:HDR
Docket No. 40-8943
04008943113E

'89 JUN 20 P1:51

PUBLIC...

MEMORANDUM FOR: Docket File No. 40-8943

FROM: Howard D. Rose, Project Manager
Uranium Recovery Field Office
Region IV

SUBJECT: RECLAMATION COST ESTIMATE FOR FERRET EXPLORATION COMPANY OF NEBRASKA, INC., CISL APPLICATION

BACKGROUND

In their March 7, 1989 letter, Ferret Exploration Company of Nebraska, Inc., (Ferret) agreed to increase their surety estimate from their $837,600 original figure to $4,872,550 in response to discussions between Mr. Bart Conroy and Mr. Steve Collings of Ferret, and Mr. Ed Hawkins and Mr. Howard Rose of the NRC.

DISCUSSION

The major issues resolved included the following:

- Ferret was notified that the surety estimate would be required to include restoration of all areas authorized in the license which would be disturbed prior to the next license renewal in compliance with Criterion 9.

- Given the limited options available for waste disposal, original cost estimates were not consistent with anticipated expenses in this area.

- The estimate to restore the 30 acres of solar evaporation ponds was not sufficient to cover backfill, recontouring and revegetation of this area.

- The licensee had not included a 15 percent contingency factor for unanticipated costs and a 10 percent management cost factor, which are considered minimums under NRC policy.

DF02
1/1

CONCLUSION

With the exception of a $5,000 typographical error, the staff considers Ferret's revised cost estimate of $4,872,550 adequate to cover estimated restoration/reclamation costs. All major issues, including a $55/cubic foot waste disposal cost, incorporation of all areas licensed for disturbance, an adjustment for evaporation pond reclamation costs and contingency fees have been resolved. The proposed figure of $4,877,550 will be the minimum required coverage in an approved surety instrument to be provided to the NRC no later than 120 days from the date of issuance of the new license. The staff recommends that the following license condition be included in the commercial license:

> The licensee shall maintain an NRC-approved financial surety arrangement, consistent with 10 CFR 40, Appendix A, Criterion 9, adequate to cover the estimated costs, if accomplished by a third party, for completion of the NRC-approved site closure plan including; above ground decommissioning and decontamination, the cost of offsite disposal of radioactive solid process or evaporation pond residues, soil and water analyses and ground-water restoration as warranted. Within three (3) months of NRC approval of a revised closure plan and cost estimate, the licensee shall submit, for NRC review and approval, a proposed revision to the financial surety arrangement if estimated costs in the newly approved site closure plan exceed the amount covered in the existing financial surety. The revised surety shall then be in effect within three (3) months of written NRC approval. Annual updates to the surety amount, required by 10 CFR 40, Appendix A, Criterion 9, shall be provided to the NRC at least three (3) months prior to the anniversary of the effective date of the existing surety instrument. If the NRC has not approved a proposed revision 30 days prior to the expiration date of the existing surety arrangement, the licensee shall extend the existing arrangement, prior to expiration, for 1 year.
>
> Along with each proposed revision or annual update, the licensee shall submit supporting documentation showing a breakdown of the costs and the basis for the cost estimates with adjustments for inflation, maintenance of a minimum 15 percent contingency, changes in engineering plans, activities performed and any other conditions affecting estimated costs for site closure. When the NRC authorizes the surety instrument to be held by the State, the licensee shall also provide the NRC with copies of surety related correspondence submitted to the State, a copy of the State's surety review and the final approved surety arrangement on an annual basis. The licensee must also ensure that the surety, where authorized to be held by the State, expressly identified the NRC related portion of the surety and covers the above ground decommissioning and decontamination, the cost of offsite disposal, soil and water sample analyses and ground-water restoration associated with the site. The basis for the cost estimate is the NRC-approved site closure plan or NRC-approved revisions to the plan.

Within 90 days of issuance of this license, Ferret Exploration Company of Nebraska, Inc., shall submit a surety instrument acceptable to the State of Nebraska and the NRC for an amount not less than $4,877,550. This surety shall be written in favor of the State or the NRC for the purpose of complying with 10 CFR 40, Appendix A, Criterion 9, until a replacement is authorized by both the State and the NRC. Ferret shall maintain the existing approved surety for the R&D license until a replacement is authorized by the NRC. Annual updates and reclamation/decommissioning plan cost estimates should follow the outline in the attachment to this license entitled, "Recommended Outline for Site Specific Reclamation and Stabilization Cost Estimates." For the purposes of NRC"s annual review, Ferret's anniversary date is designated as (to be determined at license issuance) of each successive year. The annual update should be received by the NRC 90 days prior to the anniversary date.

This license condition has been discussed with Mr. Steve Collings of Ferret Exploration Company.

Howard D. Rose, Project Manager
Uranium Recovery Field Office
Region IV

Approved by:
Edward F. Hawkins, Branch Chief
Uranium Recovery Field Office
Region IV

cc: D. Carson, State of NE, DEC
G. Konwinski, URFO

Case Closed: 040089431l3E

40-8943
40-8829

Ferret Exploration Company of Nebraska, Inc.

Suite 400
1800 Glenarm Place
Denver, Colorado 80202

Telephone (303) 295-0238
Telecopy (303) 292-6461

RETURN ORIGINAL TO PDR, HQ.

March 7, 1989

Mr. Howard Rose
U.S. Nuclear Regulatory Commission
Uranium Recovery Field Office
Box 25325
Denver, Colorado 80225

RE: Crow Butte Bond Estimate

Dear Howard:

Enclosed is a revised bond estimate for the Crow Butte commercial project and includes the remaining liability for the R&D license - the building and two small ponds. The R&D wellfield is included in the Year 1 mine unit. The estimate includes six mine units, which is the maximum number of mine units to be constructed in the proposed seven year license. Waste disposal at Hanford is estimated at $50.00/cu.ft. plus $5.00/cu.ft. transportation.

The total estimate is $4,872,550, which includes the 15% Engineering and 10% Administration Contingencies. If you have any questions regarding this estimate or need any further information, please contact me.

Sincerely,

Stephen P. Collings

Stephen P. Collings
Vice President

DF02

6.9 Financial Assessment

Following is an estimate of costs to be incurred by FEN or an independent contractor during Restoration, Decommissioning and Reclamation of the Crow Butte Site:

RESTORATION, RECLAMATION AND DECOMMISSIONING COST ESTIMATE

The FEN mine plan calls for sequential restoration and reclamation and FEN will have approximately 2 to 3 mine units in restoration, mining or reclamation at any time. The following cost estimate is based on the total cost to restore and reclaim six mine units which is the maximum number of mine units in mining or construction in the seven year mine plan. This is in accordance with Criterion 9 of 10 CFR Part 40, Appendix A.

Groundwater Restoration per Mine Unit

Average Mine Unit Size	= 22.5 acres
Average Affected Thickness	= 10.0 feet
Average Porosity	= 0.29
Average Pore Volume (PV)	= 65 acre-feet

Restoration Process Per Mine Unit

• Remove three PV for Halo Recovery and transfer to existing ponds: Pumping cost @ 40,000 KW-hr/PV	$9,500
• Treat two PV with R.O. and reinject permeate @ $2.00/100 gal: R.O. cost plus pumping cost	91,100
• Recirculate three PV with reductant Pumping cost plus chemical cost @ 1 lbs. reductant/ 1000 gal.	41,000
• Treat two PV with R.O. @ $2.00/1000 gal R.O. cost plus pumping cost	91,100
Subtotal	$232,700
Six Mine Units	$1,396,200

Sampling and Monitoring Per Mine Unit

- Phase I (as per NDEC Permit); Assume 20 representative wells per mine unit:
  20 wells x 6 parameters x 6 months @ $6.00/parameter — $4,320
- Phase II: 20 wells x 32 parameters x 2 months @ $6.00/parameter — 7,680
- Phase III: 20 wells x 32 parameters x 6 months @ 6.00/parameter — 23,040

Subtotal	$35,040
Six Mine Units	$210,240

Labor for Six Mine Units

Engineer $42,000/year x 2.5 years	$105,000
Technician $36,000/year x 2.5 years	90,000
Operator (8) $22,000/year x 2.0 years	352,000
Operator (1) $22,000/year x .5 years	11,000
	$558,000

Total Restoration, Six Mine Units	$2,164,440
Capital	200,000
	$2,364,440

Note: The above Restoration estimate is based on the following assumptions:

(1) 400 gpm R.O. equipment and all plant equipment will be existing,
(2) 400 gpm R.O. equipment purchased @ $400,000 with $200,000 salvage value.
(3) The $2.00/1000 gal operating cost for the R.O. includes electrical, chemical and maintenance,
(4) Solar evaporation ponds will be available.
(5) Restoration will take 2 years and 6 months stabilization.

Reclamation Cost per Mine Unit

- Well plugging and abandonment:
  216 mining wells and 20 monitor wells per mine unit @ $100/well — $23,600
- Surface reclamation:
  20 acres @ $1,200/acre — 27,000
- Roads and other affected areas:
  3 acres @ $1,200/acre — 3,600

Total	$54,200
Six Mine Units	$325,200

Site and Plant Decommissioning

. Plant and Office Decontamination and removal:	
- Decontaminate plant by 10% HCl	
50,000 gal at 10% = 5,000 gal @ $.50/gal	$2,500
- Decontaminate concrete	
28,000 ft2 @ $2.00/ft2	56,000
- Concrete disposal	
14,000 ft3 @ $1.00/ft3	14,000
- Disassemble plant including labor and survey	75,000
- Salvage value - equipment and building	0
- Disposal of contaminated equipment	
1500 ft3 @ $55.00/ft3	82,500
- Disassemble offices and lab (for salvage value)	0
- Wellfield facilities buildings	2,000
- Labor	
Laborer (6) @ $22,000/year for 3 months	33,000
	$265,000
. Dryer and Equipment Removal and Disposal	
- Dryer disposal	
900 ft3 @ $55.00/ft3	49,500
- Equipment Disposal	
250 ft3 @ $55.00/ft3	13,750
- Labor	
Laborer (2) @ $22,000/year for 2 months	7,350
	$70,600
. Solar Evaporation Ponds:	
- 30 acres @ $3,000/acre Reclamation	90,000
- Removal and disposal of liners (includes decontamination of liner and disposal)	70,000
	$160,000
. Removal and disposal of pond sludge	
- 5000 ft3 @ $55/ft	275,000
. Plant site, road, parking area, pipeline reclamation	
- 40 acres @ $1,200/acre	48,000
. Removal of contaminated soil around wells	
- 10 ft3 x 100 wells = 1000 ft3 @ $55/ft	55,000
. Remove, decontaminate and dispose of pipe from 6 mine units ($41,800 x 6)	250,800
. R&D Facility Decommissioning	
- Building	14,000
- Recontour pond and plant site, 5 acres @ $3,000/acre	15,000
- Remove and decontaminate buried pipeline	5,000
- Waste disposal, 1000 cu.ft @ $50/cu ft	50,000
	$84,000
Subtotal	$1,208,400

TOTAL BOND

Restoration and Reclamation	**$2,689,640**
Site and Plant Decommissioning	**1,208,400**
	$3,898,040
Engineering Contingency - 15%	**584,706**
Contract Administration Contingency - 10%	**389,804**
TOTAL BOND	**$4,872,550**

NRC Form 374
(5-84)

U.S. NUCLEAR REGULATORY COMMISSION

MATERIALS LICENSE

Pursuant to the Atomic Energy Act of 1954, as amended, the Energy Reorganization Act of 1974 (Public Law 93-438), and Title 10, Code of Federal Regulations, Chapter I, Parts 30, 31, 32, 33, 34, 35, 40 and 70, and in reliance on statements and representations heretofore made by the licensee, a license is hereby issued authorizing the licensee to receive, acquire, possess, and transfer byproduct, source, and special nuclear material designated below; to use such material for the purpose(s) and at the place(s) designated below; to deliver or transfer such material to persons authorized to receive it in accordance with the regulations of the applicable Part(s). This license shall be deemed to contain the conditions specified in Section 183 of the Atomic Energy Act of 1954, as amended, and is subject to all applicable rules, regulations and orders of the Nuclear Regulatory Commission now or hereafter in effect and to any conditions specified below.

Licensee	
1. Everest Minerals Corporation	3. License number: SUA-1511, Amendment No. 1
2. P.O. Box 1210 Glenrock, Wyoming 82637	4. Expiration date: July 1, 1993
	5. Docket or Reference No.: 40-8857

6. Byproduct, source, and/or special nuclear material	7. Chemical and/or physical form	8. Maximum amount that licensee may possess at any one time under this license
Uranium	Unspecified	Unlimited

9. The authorized place of use shall be the licensee's Highland project facilities in Converse County, Wyoming.

10. For use in accordance with statements, representations, and conditions contained in Sections 3 and 4 of the licensee renewal application dated December 1985, and the licensee's submittal dated June 12, 1987, except where superseded by license conditions below.

11. The licensee is hereby exempted from the requirements of Section 20.203(e)(2) of 10 CFR 20 for areas within the facility, provided that all entrances to the facility are conspicuously posted in accordance with Section 20.203(e)(2) and with the words, "Any area within this facility may contain radioactive material."

12. Standard operating procedures (SOPs) shall be established for all operational process activities involving radioactive materials that are handled, processed, or stored. Standard operating procedures for operational activities shall enumerate pertinent radiation safety practices to be followed. Additionally, written procedures shall be established for nonoperational activities to include in-plant and environmental monitoring, bioassay analyses, and instrument calibrations. An up-to-date copy of each written procedure shall be kept in the process area to which it applies.

13. All written procedures for both operational and nonoperational activities shall be reviewed and approved in writing by the RSO and the Corporate RSO before implementation and whenever a change in a procedure is proposed to ensure that proper radiation protection principles are being applied. In addition, the Corporate RSO shall perform a documented review of all existing operating procedures at least annually.

storage facility which results in an uncontrolled release of radioactive materials, or of any unusual conditions which if not corrected could lead to such a failure. Such notification shall be followed, within 7 days, by submittal of a written report detailing the conditions leading to the failure or potential failure, corrective actions taken, and results achieved. This requirement is in addition to the requirements of 10 CFR Part 20.

45. At least six (6) months prior to termination of uranium recovery in a mining area, the licensee shall submit to the USNRC, Uranium Recovery Field Office, in the form of a license amendment, a plan for ground-water restoration and post restoration monitoring. The goal of restoration shall be to return the ground-water quality, on a mining unit average, to baseline concentrations. Additionally, failure to restore ground-water quality to baseline concentrations shall require the licensee to submit a report describing the methodology actually implemented during the restoration attempt, predicted results of any subsequent restoration efforts to further lower ground-water concentrations and an evaluation of the impacts of the remaining ground-water contamination.

46. The licensee shall maintain an NRC-approved financial surety arrangement, consistent with 10 CFR 40, Appendix A, Criterion 9, adequate to cover the estimated costs, if accomplished by a third party, for completion of the NRC-approved site closure plan including; above ground decommissioning and decontamination, the cost of offsite disposal of radioactive solid process or evaporation pond residues, and ground-water restoration as warranted. Within three (3) months of NRC approval of a revised closure plan and cost estimate, the licensee shall submit, for NRC review and approval, a proposed revision to the financial surety arrangement if estimated costs in the newly approved site closure plan exceed the amount covered in the existing financial surety. The revised surety shall then be in effect within three (3) months of written NRC approval. Annual updates to the surety amount, required by 10 CFR 40, Appendix A, Criterion 9, shall be provided to the NRC at least three (3) months prior to the anniversary of the effective date of the existing surety instrument. If the NRC has not approved a proposed revision 30 days prior to the expiration date of the existing surety arrangement, the licensee shall extend the existing arrangement, prior to expiration, for 1 year.

Along with each proposed revision or annual update, the licensee shall submit supporting documentation showing a breakdown of the costs and the basis for the cost estimates with adjustments for inflation, maintenance of a minimum 15 percent contingency, changes in engineering plans, activities performed and any other conditions affecting estimated costs for site closure. The licensee shall also provide the NRC with copies of surety related correspondence submitted to the State, a copy of the State's surety review and the final approved surety arrangement. The licensee must also ensure that the surety, where authorized to be held by the State, expressly identifies the NRC related portion of the surety and covers the above ground decommissioning and decontamination, the cost of offsite disposal, soil and water sample analyses and ground-water restoration

associated with the site. The basis for the cost estimate is the NRC approved site closure plan or the NRC approved revisions to the plan.

Prior to actual operation, Everest Minerals Corporation shall submit a surety instrument acceptable to the State of Wyoming and the NRC for an amount not less than $2,233,000, in favor of the State of Wyoming, and shall be continuously maintained for the purpose of complying with 10 CFR 40, Appendix A, Criterion 9, until a replacement is authorized by both the State and the NRC. The NRC's site closure estimate represents $2,233,000 of this surety arrangement.

Attachment No. 3 "outlines the minimum considerations used by the NRC in the review of site closure estimates." Reclamation/decommissioning plans and annual updates should follow this outline.

47. The results of all effluent and environmental monitoring required by this license shall be reported in accordance with 10 CFR 40, Section 40.65 with copies of the report sent to the USNRC, Uranium Recovery Field Office. Monitoring data shall be reported in the format shown in the Attachment No. 2, "Sample Format for Reporting Monitoring Data."

48. The licensee shall implement the effluent and environmental monitoring program specified in Section No. 4 of the December 1985 renewal application, as well as Section No. 2 of the July 1986 Wastewater Land Disposal Application, and Section No. 7 of the April 1986, Wyoming Groundwater Pollution Control Permit for Subsurface Injection of Mineral Processing Waste. Additionally, the licensee shall implement an air particulate monitoring program external to the main processing facility in accordance with 10 CFR Part 20.

FOR THE NUCLEAR REGULATORY COMMISSION

Date: SEP 23 1987

R. Dale Smith, Director
Uranium Recovery Field Office
Region IV

40-8857

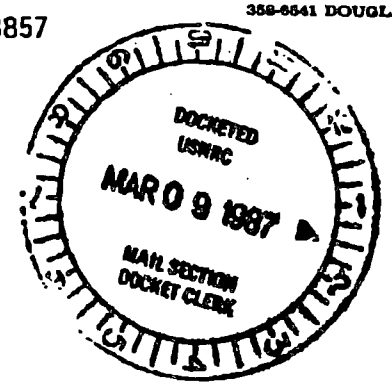
EVEREST MINERALS CORPORATION
POST OFFICE BOX 1210
GLENROCK, WYOMING 82637

RETURN ORIGINAL TO PDR, HQ.

March 4, 1987

AREA CODE 307
235-1626 CASPER
358-6541 DOUGLAS

Docket No. 40-8857



Mr. Howard D. Rose
Project Manager
USNRC-URFO
P.O. Box 25325
Denver, Colorado 80225

Dear Howard:

As we discussed in your office on February 25, I am submitting with this letter back-up calculations for the bond calculation for the Highland Uranium Project. Two documents are attached:

1) Table 3.9 from the License Application, pages 107D through 107G, "Reclamation Cost Calculation Summary" dated February 1987, and

2) my calculation sheets, numbered 1 of 10 through 10 of 10, dated January 11, 1987.

These provide the detailed breakdown of the reclamation cost calculations. I might note that the totals of the two differ by $1k due to rounding on Table 3.9 where amounts are given in even thousands of dollars.

The calculation relied predominantly on actual cost data to which Everest had access, and is not from engineering handbook estimates. The cost estimates are calculated as if the work were done by a contractor, has an additional 6% management fee added, includes $102k for contractor's performance insurance, and 15% contingency on the total after adding those items. The primary sources of data used were:

1) Exxon mill decommissioning actual costs for facilities dismantling and disposal, including radiation surveys

2) Exxon actual costs for clean-up of contaminated soils and concrete areas, including radiation surveys

3) Everest actual cost for surface reclamation, topsoiling, and revegetation at the Highland site

4) Everest actual cost for groundwater restoration, operation of reverse osmosis equipment, and addition of a hydrogen sulfide reductant from 1986 groundwater restoration of the R&D Pilot

5) Wyoming Department of Environmental Quality actual costs for cased well abandonment

DESIGNATED ORIGINAL

Certified By _____

87-426

6) Everest actual cost for operating radium-226 removal facility, disposal injection well, and land application (irrigation) system.

Therefore, virtually all of the cost calculations are based on real data rather than speculative estimates.

The total bond calculation is probably higher than actual due to the following conservative factors which are "built into" the calculations:

1) all labor cost is estimated at $125 per man day. Current labor cost, at $8 to $9 per hour, with 25% benefit loading, would range from $80 to $90 per man day, or 64% to 72% of the $125 rate used in these calculations

2) all contaminated material disposal is assumed to be hauled up to 1500 miles, or $3000 per truckload. Disposal at a closer site is likely. Current operators of existing tailings facilities in Wyoming have indicated they would accept such wastes for their nominal incremental cost of reclamation incurred by such acceptance

3) no salvage value is taken for buildings, electrical equipment, motors, or other uncontaminated facilities

4) groundwater restoration is included for the entire Section 21 mining area (the first 3½ years of production) although Wyoming statuate only requires bonding for the first year of production (W.S. 35-11-417(c)(i)). The bond amount would be adjusted as required through the Annual Report as additional lands or groundwater are affected (W.S. 35-11-417(f)).

5) capital cost of $120,000 for an additional reverse osmosis unit is included, although the Project already has an adequate R.O. on-site.

6) costs to remove certain facilities, like the main access road, are included although the landowner would probably request that some of these be left intact for his future use

7) the 15% contingency requested by both WDEQ and NRC is probably quite high considering that most of these calculations are based on actual costs at Highland or similar facilities.

Therefore, I believe the true reclamation cost could be as much as 25% to 30% less than the $2,233,000 total given on Table 3.9.

Should you have any questions regarding the bond calculation, please give me a call. WDEQ has formally accepted the $2,233,000 bond amount and Everest is pursuing bonding options based on that amount.

Sincerely,

Stephen P. Morzenti
Project Manager

SPM/ksj

cc: W.M. Mays, w/att
File 4.2 w/att
File 4.6.3 w/o att

1/4

Table 3.9

Highland Uranium Project
Reclamation Cost Calculation Summary
1986 Dollars in Thousands
(escalated to 1987 on page 107E)

1.	Buildings	
1.1	Dismantle Yellowcake Areas	
	Drier Area	
	1. (30.8 k cu ft area)($.53/cu ft) = based on actual costs from Exxon decom, including radiation safety	$16
	2. Disposal volume 10% of built = 3.1 k cu ft	
	2 truckloads at $3 k per load =	6
	Disposal at $2/cu ft =	6
	3. Drier intact, 3000 cu ft	
	Labor, (25 man days)($125/man day) =	3
	Trucking, (2 loads)($3 k/load) =	6
	Disposal (3 k cu ft)($2/cu ft) =	6
1.2	Tankage, cut and remove 36,500 cu ft tankage in 20 tanks	
	(20 tanks)(3 man crew)(1 tank/day) =	
	(60 man days)($125/man day) =	8
	Equipment rental =	6
	Trucking, 3,650 cu ft = 2 truckloads	
	(2 loads)($3 k/load) =	6
	Disposal (3,650 cu ft)($2/cu ft) =	7
1.3	Remove Contaminated Piping	
	5000 ft	
	100 ft/man day = 50 man days	
	(50 man days)($125/man day) =	6
	(2 truckloads)($3 k/truckload) =	6
	Disposal =	6
1.4	Remove Contaminated Pumps	
	(50 pumps)(0.5 man day/pump)	
	= (25 man days)($125/man day) =	3
	(1 truckload)($3 k/truckload) =	3
	Disposal =	6
1.5	Decontamination	
	131,000 sq ft area surface wash	
	Wash cost $0.50/sq ft	
	Disposal cost $0.10/sq ft	
	(131 k sq ft)($0.60/sq ft) =	79
	Concrete Wash	
	8100 sq ft concrete surface	

	(8.1 k sq ft)($2/sq ft) =	16
	Disposal at $0.40/sq ft	
	(8.1 k sq ft)($0.40/sq ft) =	3
1.6	Remove utilities	
	Electricals - at salvage cost =	0
	Water tankage =	20
	Parking Areas Removal/Disposal	
	(2,000 cu yd)($5/cu yd) =	10
	Chemical Receiving Area Removal/Disposal	
	(1,200 cu yd)($5/cu yd) =	6
1.7	Wellfield Buildings	
	(4 header houses)($10 k/building) =	40
1.8	Retopsoil and Revegetate Building Areas	
	(12 acres)($2,000/acre) =	24
	GROUP 1 SUBTOTAL	$298
2.	Groundwater Restoration - Section 21 Mine Area	
2.1	275 patterns, 83.5 AF per pore volume (PV)	
	(3 PV pumped to irrigation)(1.26 MWh/PV)	
	electrical cost =	120
	(2 PV RO treatment)($2.38/1000 gal) =	130
	2 PV pumping electrical cost =	80
	RO cap ex for Section 21 =	120
	Make-up water pumping costs (2PV)(.33)($40 k/PV) =	26
	Dilution water to irrigation pumping costs	
	(2 PV)(.67)($40 k/PV) =	54
2.2	Sampling and Monitoring	
	(275 patterns)(3 wells/pattern) = 825 wells	
	If 5% sampled, is 41 wells, sampled twice per year	
	7 years, is (600 samples)($125/sample) =	75
2.3	Environmental Labor	
	1 technician, half time, ($30 k/yr)(7 yr) =	105
2.4	Operating Maintenance Parts, estimated =	50
2.5	Chemical Reductant	
	If required on 25% of patterns	
	(70 patterns)($360/pattern) =	25
2.6	Radium Removal	
	(5 PV)(27,200,000 gal/PV)($0.001/gal) =	136
2.7	Pumping to Irrigation	
	(5 PV)($10 k/PV) =	50
2.8	Irrigation Sampling/Monitoring	
	(40 months)($300/mo) =	

2.9	Irrigation Maintenance/Operating Cost (40 months)($800/month) =	32
	Group 2, Total without Performance Insurance	1,015
	Group 2 Insurance, (subtotal)(10%) =	102
	GROUP 2 SUBTOTAL	$1,117
3.	Wellfield Reclamation, Section 21	
3.1	Hole Plugging (275 patterns)(3 wells/pattern)($150/well) =	124
	(40 monitor wells)($150/well) =	6
3.2	Pattern Area Reclamation (37 acres)($1,200/acre) =	44
3.3	Roads and Assoc. Structures (12 acres)($1,200/acre) =	14
	GROUP 3 SUBTOTAL	$188
4.	Associated Structures	
4.1	Access Roads (3 miles)(30 feet wide) = 11 acres (11 acres)($1,200/acre) =	13
4.2	Pipelines (2 miles)(10 feet wide) = 2.4 acres (2.4 acres)($1,200/acre) =	3
4.3	Radium Removal Ponds Liner removal and disposal, 3,100 BCY x $8/BCY	25
	Recontour, 6,000 BCY x $3/BCY	18
	Topsoil and Revegetate, (2 acres)($1,200/acre)	2
4.4	Storage Pond Recontour, 83,000 BCY x $1.06/BCY	88
	Topsoil and Revegetate (10 acres)($1,200/acre) =	12
4.5	Revegetate Irrigation Area (54 acres)($250/acre) =	14
	GROUP 4 SUBTOTAL	$175
5.	TOTALS	
5.1	Buildings	$298
5.2	Groundwater Restoration	1,11

5.3	Wellfield Reclamation	188
5.4	Associated Structures	175
	Sub Total	$1,778
5.5	Overhead and Management	107
	Sub Total	$1,885
5.6	15% Contingency	283
5.7	Total with OH and Contingency	$2,168
5.8	3% 1986 GNP inflator	65
5.9	Total Bond in 1987 Dollars	$2,233

NRC Form 374 (5-84) U.S. NUCLEAR REGULATORY COMMISSION PAGE 1 OF 7 PAGES

MATERIALS LICENSE

Pursuant to the Atomic Energy Act of 1954, as amended, the Energy Reorganization Act of 1974 (Public Law 93 438), and Title 10, Code of Federal Regulations, Chapter I, Parts 30, 31, 32, 33, 34, 35, 40 and 70, and in reliance on statements and representations heretofore made by the licensee, a license is hereby issued authorizing the licensee to receive, acquire, possess, and transfer byproduct, source, and special nuclear material designated below; to use such material for the purpose(s) and at the place(s) designated below; to deliver or transfer such material to persons authorized to receive it in accordance with the regulations of the applicable Part(s). This license shall be deemed to contain the conditions specified in Section 183 of the Atomic Energy Act of 1954, as amended, and is subject to all applicable rules, regulations and orders of the Nuclear Regulatory Commission now or hereafter in effect and to any conditions specified below.

Licensee	
1. Uranerz U.S.A., Inc. 2. 165 South Union Blvd. Suite 280 Lakewood, Colorado 80228	3. License number: SUA-1540, As Issued 4. Expiration date: December 31, 1995 5. Docket or Reference No.: 40-8981

6. Byproduct, source, and/or special nuclear material	7. Chemical and/or physical form	8. Maximum amount that licensee may possess at any one time under this license
Uranium	Unspecified	1,000,000 pounds

9. The authorized place of use shall be the licensee's North Butte facility in Campbell County, Wyoming.

10. For use in accordance with statements, descriptions and representations contained in Sections 15, 16.1 to 16.4, 16.5 to 16.12 and 19 of the licensee's revised application submitted by cover letter dated March 7, 1989.

Notwithstanding the above, the following conditions shall override any conflicting statements contained in the licensee's application and supplements.

11. The annual throughput shall not exceed a flow rate of 3000 gallons per minute, exclusive of restoration flow resulting in a production rate of 700,000 pounds of U_3O_8.

12. Any significant changes in the process circuit as shown in Figure 15.21 of the application, dated March 7, 1989, shall require approval by the NRC, Uranium Recovery Field Office in the form of a license amendment. Three months prior to initiation of construction detailed process flow diagrams shall be submitted to the NRC, Uranium Recovery Field Office, for review and approval.

13. Release of equipment or packages from the restricted area shall be in accordance with the attachment to this license entitled, "Guidelines for Decontamination of Facilities and Equipment Prior to Release for Unrestricted Use or Termination of Licenses for Byproduct or Source Materials," dated September 1984.

14. The results of effluent and environmental monitoring described in the submittal dated November 13, 1990 shall be reported in accordance with 10 CFR Part 40, Section 40.65, to the NRC, Uranium Recovery Field Office. The report shall also include injection rates, recovery rates and injection manifold pressures.

NRC Form 374A (3-84) U.S. NUCLEAR REGULATORY COMMISSION

MATERIALS LICENSE
SUPPLEMENTARY SHEET

PAGE 5 OF 7 PAGES

License number: SUA-1540

Docket or Reference number: 40-8981

cost estimate, the licensee shall submit, for NRC review and approval, a proposed revision to the financial surety arrangement if estimated costs in the newly-approved site closure plan exceed the amount covered in the existing financial surety. The revised surety shall then be in effect within 3 months of written NRC approval.

Annual updates to the surety amount, required by 10 CFR 40, Appendix A, Criterion 9, shall be provided to the NRC at least 3 months prior to the anniversary of the effective date of the existing surety instrument. If the NRC has not approved a proposed revision 30 days prior to the expiration date of the existing surety arrangement, the licensee shall extend the existing arrangement, prior to expiration, for 1 year. Along with each proposed revision or annual update, the licensee shall submit supporting documentation showing a breakdown of the costs and the basis for the cost estimates with adjustments for inflation, maintenance of a minimum 15 percent contingency, changes in engineering plans, activities performed, and any other conditions affecting estimated costs for site closure. The licensee shall also provide the NRC with copies of surety related correspondence submitted to the State of Wyoming, a copy of the State's surety review, and the final approved surety arrangement. The licensee must also ensure that the surety, where authorized to be held by the State, expressly identifies the NRC-related portion of the surety and covers the above-ground decommissioning and decontamination, the cost of offsite disposal, soil and water sample analyses, and ground-water restoration associated with the site. The basis for the cost estimate is the NRC-approved site closure plan or the NRC-approved revisions to the plan. The reclamation/decommissioning plan, cost estimates, and annual updates should follow the outline in the attachment to this license entitled, "Recommended Outline for Site Specific Reclamation and Stabilization Cost Estimates."

Three months prior to the expected commencement of site construction, the licensee shall submit a surety instrument acceptable to the State of Wyoming and the NRC in an amount no less than $4,920,705. This surety shall be written in favor of the State of Wyoming or the NRC for the purpose of complying with 10 CFR 40, Appendix A, Criterion 9, and shall be continuously maintained until a replacement is authorized by both the State and the NRC. Site construction activities shall not be commenced until the NRC and the State accept the surety arrangement.

36. In addition to the inspection and audit program described in Section 19.1.3 of the application, dated March 7, 1989, the RSO or trained assistant shall document a daily walkthrough of the facility to determine if radiation control practices are being implemented.

37. The licensee shall submit to the NRC, Uranium Recovery Field Office, a copy of the semiannual ALARA audit report containing the information specified in Section 19.1.3 of the application dated March 7, 1989, within 2 months of the end of the reporting period. The report shall also include a summary of the daily walkthrough inspections.

38. The licensee shall implement the radiological surveys described in Sections 19.1.7.2, 19.1.7.5, 19.1.7.6, and 19.1.7.8 at the locations specified in Figure 19.2 of the application dated, March 7, 1989. Additionally, alpha surveys, at the designated

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40-8981

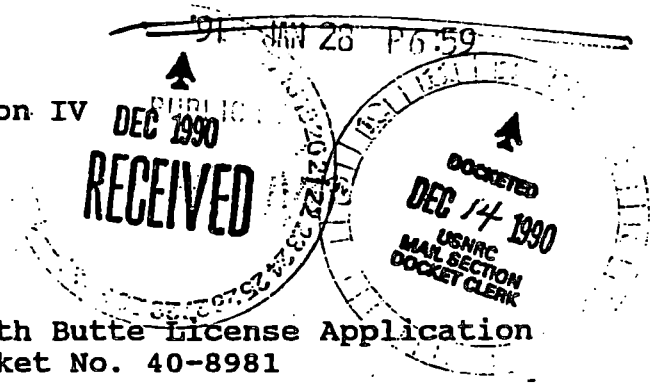
URANERZ U.S.A., INC.

165 S. UNION BOULEVARD, SUITE 280, DENVER, COLORADO 80228

Telephone (303) 985-1511
Telex: 45-4362

RETURN ORIGINAL TO PDR, HQ.

December 14, 1990



Mr. Ramon Hall, Director
Uranium Recovery Field Office, Region IV
U.S. Nuclear Regulatory Commission
P.O. Box 25325
Denver, Colorado 80225

Attn.: Mr. Gary Konwinski

Re: North Butte License Application
Docket No. 40-8981

Ruth License Application
Docket No. 40-8958

Subject: Revisions to Reclamation/Decommission Bonding Sections

Dear Mr. Hall:

In response to a request from Mr. Gary Konwinski, Uranerz herewith submits revisions to the reclamation/decommission bonding section for both the Ruth and North Butte Source Material License applications. Four sets of revised pages are included for each application. It is requested that the revised pages be inserted into your copies of both applications.

Thank you very much for your assistance with this matter. Please get in touch with me at Uranerz' Denver office if you or your staff have any questions.

Sincerely,

URANERZ U.S.A., INC.

Glenn J. Catchpole
Manager of Regulatory Affairs
and Environmental Engineering

GJC/jb

Encl.

DESIGNATED ORIGINAL

Mary C. Hood [redacted]

DF02

Addl Info 11.

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7) All contaminated materials including the ponds residue will be trucked to an NRC licensed disposal facility located in the Gas Hills.

The aquifer restoration and surface reclamation operations have each been broken down into a number of phases and a cost estimate for each phase has been prepared. A summary of these cost estimates by phase is presented in Table 17.2. Following the table are the individual cost breakdowns for each phase of restoration and reclamation. The total estimate of decommissioning cost of $1,685,394.00 includes a contractor's profit of 15 percent, a contingency of 15 percent and DEQ project management fee of 5 percent.

17.6 BONDING

Once the Wyoming DEQ, the U.S.N.R.C., and Uranerz U.S.A., Inc. have agreed to the estimated reclamation and restoration costs, a reclamation performance bond, letter of credit, or other acceptable surety will be submitted to the LQD/DEQ with a copy to the NRC.

TABLE 17.2

SUMMARY of DECOMMISSIONING COST SCHEDULE

DECOMMISSIONING ITEM	AMOUNT
AQUIFER RESTORATION	
Phase I - Site Preparation	$ 482,990
Phase II - Water Circulation and Treatment	1,060,865
Phase III - Stability Period	329,600
SURFACE RECLAMATION	
Phase I - Well Field Dismantling	850,600
Phase II - Pond Dry Out Period	76,000
Phase III - Ponds Sludge Removal	684,770
Phase IV - Backfill Ponds, Recontour, Topsoil Application, Seeding and Mulching	135,142
Phase V - Post Decommissioning Site Monitoring For Revegetation Success and Final Fence Removal	25,000
SUBTOTAL	3,644,967
Contingency (15%)	546,745
Contractors Profit (15%)	546,745
DEQ Project Management (5%)	182,248
TOTAL	$4,920,705

Note: Cost details on each phase of the aquifer restoration and surface reclamation are located at the end of this Section.

AQUIFER RESTORATION COSTS - PHASE I

EXPENSE ITEM	Amount
CONTRACTOR SITE EXPENSES	
Personnel	23,040.00
Mobile Equip. & Vehicles	10,000.00
Electricity	2,000.00
Heating	1,000.00
Maintenance	2,000.00
Site Office	100.00
Safety	50.00
Chemicals	0.00
Membrane Cleaning	0.00
Filtering	0.00
Reductant	0.00
Lab. Consumables	300.00
Miscellaneous	2,000.00
CONTRACTORS OVERHEAD	
Project Manager	5,000.00
Insurance	3,000.00
Office Overhead	3,000.00
Travel	1,000.00
Miscellaneous	1,000.00
OUTSIDE SERVICES	
Commercial Laboratory	500.00
Consultants	2,000.00
CAPITAL EQUIPMENT	
Reverse Osmosis Units	225,000.00
R.O. Unit Support Equip.	25,000.00
Mobile Equipment	122,000.00
Miscellaneous Plant/Wellfield Equip.	45,000.00
Radiation Monitoring Equipment	10,000.00
TOTAL	$ 482,990.00

PERIOD DESCRIPTION AND COST EXPLANATION: Phase I

Phase I of the aquifer restoration operation will last for one month during which time the site will be prepared for aquifer restoration activities. The Reverse Osmosis (RO) units will be delivered to the site and installed into the restoration circuit. Necessary piping changes will be completed in the plant and in the well field. The pipelines will be pressure tested and repaired as necessary. Minor electrical changes required in the plant will be completed. Required mobile equipment including a pump pulling unit, acid trailer, backhoe, air compressor and pickup trucks will be purchased and delivered to the site.

The estimate of restoration and reclamation (decommissioning) costs is based on the mine being abandoned by the operator and the regulatory agencies engaging the services of a "contractor" to perform the required decommissioning work. Further, the cost figures assume the building and fixed equipment at the mine at the time of abandonment will be available to the contractor to perform the decommissioning work. This equipment includes plant building, tanks, pumps, pipelines, and deep disposal well. Consultants will be utilized to perform such services as NRC ALARA audits, electrical changes and repairs, and other skill specific jobs not available on the contractor's staff. A commercial laboratory will be utilized for water quality analyses.

AQUIFER RESTORATION COSTS - PHASE II

EXPENSE ITEM	Amount
CONTRACTOR SITE EXPENSES	
Personnel	414,720
Mobile Equip. & Vehicles	18,000
Electricity	90,000
Heating	24,000
Maintenance	39,000
Site Office	1,800
Safety	900
Chemicals	28,251
Membrane Cleaning	12,201
Filtering	11,664
Reductant	19,929
Deep Disposal Well Operation	108,000
Lab. Consumables	5,400
Miscellaneous	36,000
CONTRACTORS OVERHEAD	
Project Manager	90,000
Insurance	54,000
Office Overhead	54,000
Travel	18,000
Miscellaneous	18,000
OUTSIDE SERVICES	
Commercial Laboratory	9,000
Consultants	3,000
CAPITAL EQUIPMENT	
Reductant Equipment	5,000
TOTAL	$ 1,060,865

PERIOD DESCRIPTION AND COST EXPLANATION: Phase II

Phase II of the aquifer restoration operation will last for 18 months during which time approximately six pore volumes of RO treated water will be circulated through each well field being restored. The estimated costs include the use of a reductant during the last month of aquifer restoration which will only be used if necessary to achieve the restoration goals. At this time it is felt that the addition of a reductant will not be necessary. Uranerz feels that restoration will be achieved after circulating four pore volumes of RO treated water through each well field. The additional two pore volumes are included in the cost calculations to make the estimate conservative. Brine from the operation of the R.O. unit will be discharged to the deep disposal well or the evaporation ponds.

Total amount of RO treated water circulated through each well field at 300 GPM amounts to 80,000,000 gallons (per well field) or 6.6 pore volumes. Cost estimates are based on the maximum exposure (two well fields contaminated) during the 5 year term of the Source Material License.

AQUIFER RESTORATION COSTS - PHASE III

EXPENSE ITEM	Amount
CONTRACTOR SITE EXPENSES	
Personnel	33,000.00
Mobile Equip. & Vehicles	12,000.00
Electricity	16,000.00
Heating	16,000.00
Maintenance	6,000.00
Site Office	1,200.00
Safety	600.00
Chemicals	0.00
Membrane Cleaning	0.00
Filtering	0.00
Reductant	0.00
Lab. Consumables	0.00
Miscellaneous	6,000.00
CONTRACTORS OVERHEAD	
Project Manager (part time)	30,000.00
Insurance	12,000.00
Office Overhead	12,000.00
Travel	6,000.00
Miscellaneous	6,000.00
OUTSIDE SERVICES	
Commercial Laboratory	6,000.00
Consultants	2,000.00
CAPITAL EQUIPMENT	
Reductant Equipment	0.00
TOTAL (per well field)	164,800.00

TOTAL FOR TWO WELL FIELDS (times 2) $ 329,600.00

PERIOD DESCRIPTION AND COST EXPLANATION: Phase III

Phase III of the aquifer restoration operation is the 12 month stability period. During this period the contractor will only have a foreman working at the site. The well field and plant will remain in tact in case the stability period is not successful and restoration operations have to start back up. The building will be kept heated during cold weather so that pipes, pumps and other equipment do not get damaged from freezing. The pipelines in the well field will be drained so that they do not freeze and break.

During the stability period the restoration sampling wells will be sampled once a month and analyzed for the full guideline 8 list of parameters. The contractor will provide monthly reports to the regulatory agencies during the stability period that include the water quality data from the restoration sampling wells. The contractor will also provide the regulatory agencies with a final report on the entire aquifer restoration operation.

SURFACE RECLAMATION COSTS - PHASE I

EXPENSE ITEM	Amount
CONTRACTOR SITE EXPENSES	
Personnel	198,000.00
Vehicle- fuel	6,200.00
Vehicle- Maint.	8,000.00
Power	8,000.00
Mobile Equip.- Fuel	3,000.00
Mobile Equip.- Maint.	3,000.00
Commercial Lab.	3,000.00
Bentonite Abandonment Pellets	33,600.00
Inert Material	28,000.00
Disposal Well Abandonment	25,000.00
Disposal Fees	406,500.00
Misc. Equipment	4,000.00
CONTRACTORS OVERHEAD	
Project Manager	30,000.00
Insurance	18,000.00
Office Overhead	18,000.00
Travel	6,000.00
Miscellaneous	12,000.00
OUTSIDE SERVICES	
Radiation Surveys	20,000.00
Trucking	20,300.00
TOTAL	$ 850,600.00

PERIOD DESCRIPTION AND COST EXPLANATIONS: Phase I

Phase I of the surface reclamation activities will last three months and will involve well field dismantling and well abandonment, plus process equipment decontamination and removal. Remove all process equipment, pipe, pumps, fittings, etc. from site. Totally decontaminate building. Abandonment of deep disposal well.

Contractor means the firm engaged by the regulatory agencies to perform the decommissioning work. Outside services means commercial laboratories, consultants, and subcontractors utilized by the contractor during the decommissioning activities.

Contractor will use employees to perform required site work during Phase I. The only subcontractor will be a trucking company to transport the equipment, pipe, pumps fittings, etc. to a disposal site. Twenty truck loads of contaminated equipment, piping, etc. to be hauled to Gas Hills (400 miles round trip times $1.75 per mile times 20 trips equals $14,000.00). Thirty truck loads of non-contaminated equipment, parts, pipe, etc. to the land fill at Gillette, WY (120 miles round trip times $1.75 per mile times 30 trips equals $6,300.00). Disposal of pond sludge, pond liners the building is covered in Phase III.

The disposal fee at Gas Hills for contaminated equipment is estimated at $27 per cubic ft. (15,000 cubic ft. times $27 equals $405,000). The disposal fee at the Gillette land fill is estimated at $50 per load ($50 per load times 30 loads equals $1,500.00).

The materials cost for well plugging chips is $3.00 per bag delivered to the North Butte site. There will be 560 wells to plug and cap. The bentonite chips bags will be 50 pound bags and seven bags will be placed in each well (20 bags times $3 per bag times 560 wells equals $33,600.00). The cost of inert material is estimated at $75.00 per well ($55 times 560 wells = $28,000.00).

SURFACE RECLAMATION COSTS - PHASE II

EXPENSE ITEM	Amount
CONTRACTOR SITE EXPENSES	
Personnel	0.00
Vehicle- fuel	0.00
Vehicle- Maint.	0.00
Power	0.00
Mobile Equip.- Fuel	0.00
Mobile Equip.- Maint.	0.00
Commercial Lab.	0.00
Disposal Fees	0.00
Misc. Equipment	1,000.00
CONTRACTORS OVERHEAD	
Project Manager	22,500.00
Insurance	7,500.00
Office Overhead	15,000.00
Travel	7,500.00
Miscellaneous	7,500.00
OUTSIDE SERVICES	
Radiation Surveys	0.00
Pond/Site Inspector	15,000.00
TOTAL	$ 76,000.00

PERIOD DESCRIPTION AND COST EXPLANATIONS: Phase II

Phase II of the surface reclamation activities will last fifteen months and is the interim period for the ponds to dry (estimate no more than two years after restoration discharges to pond cease). During Phase II the only site requirement will be the weekly check of the evaporation ponds. The weekly pond check will be subcontracted.

SURFACE RECLAMATION COSTS - PHASE III

EXPENSE ITEM	Amount
CONTRACTOR SITE EXPENSES	
Personnel	6,100.00
Vehicle- fuel	500.00
Vehicle- Maint.	300.00
Power	1,500.00
Mobile Equip.- Fuel	0.00
Mobile Equip.- Maint.	0.00
Commercial Lab.	1,000.00
Misc. Equipment	1,000.00
CONTRACTORS OVERHEAD	
Project Manager (part time)	2,500.00
Insurance	500.00
Office Overhead	1,000.00
Travel	500.00
Miscellaneous	500.00
OUTSIDE SERVICES	
Radiation Surveys	8,000.00
Trucking	27,300.00
Disposal Fees	568,620.00
Earthwork	3,450.00
Building Demolition and Removal	62,000.00
TOTAL	$ 684,770.00

PERIOD DESCRIPTION AND COST EXPLANATIONS: Phase III

Phase III of the surface reclamation activities will last one month and is for the removal of the contaminated sludge in the bottom of the three evaporation ponds. It is estimated that the depth of sludge in the bottom of the ponds after evaporation is complete will be about six inches in the first pond. Six inches of sludge is equivalent to 740 cubic yards of material. For purposes of estimating, it is assumed that the material will be contaminated and will be trucked to Gas Hills. A round trip to Gas Hills from the North Butte site is 400 miles. It will take 37 trips to haul the sludge to Gas Hills at a cost of $1.75 per mile. The cost for the 37 trips is $25,900.00 (400 miles times $1.75 per mile times 37 trips equals $25,900.00).

For purposes of estimating reclamation costs it is assumed that the artificial pond liner in pond one is also contaminated and will be disposed of at an NRC licensed facility in Gas Hills. The liners will be hauled to Gas Hills in two (20 cubic yds.) trips for a cost of $1,400.00 (400 miles times $1.75 per mile times 2 trip equals $1,400.00). The contaminated portion of the building will also be disposed of in the Gas Hills in two loads (20 cubic yds.) at a transportation cost of $1,400. The total volume of contaminated materials (pond sludge, building and liners) is 780 cubic yds. (21,060 cubic ft.). The disposal fee at the Gas Hills is therefore $ 568,620.

The earthwork cost is broken down as 45 hours of front end loader work for the sludge plus 6 hours of front end loader work for the liner at an hourly rate of $60 per hour. Also included is $750 for equipment mobilization giving a total of $3,450.00.

The removal of the stock fence around the evaporation ponds is covered under the contractors personnel expenses.

The project site will receive a gamma survey using the same grid system established for the gamma survey baseline studies. The volume of material (sludge) in the ponds will be relatively small because the majority of the waste water will be routed to the deep disposal well.

SURFACE RECLAMATION COSTS - PHASE IV

EXPENSE ITEM	Amount
CONTRACTOR SITE EXPENSES	
Personnel	10,100.00
Vehicle- fuel	1,000.00
Vehicle- Maint.	1,000.00
Power	0.00
Mobile Equip.- Fuel	0.00
Mobile Equip.- Maint.	0.00
Commercial Lab.	0.00
Disposal Fees	0.00
Mulch	2,500.00
Seed	12,144.00
Misc. Equipment	2,000.00
CONTRACTORS OVERHEAD	
Project Manager (part time)	2,500.00
Insurance	500.00
Office Overhead	1,000.00
Travel	500.00
Miscellaneous	1,000.00
OUTSIDE SERVICES	
Radiation Surveys	2,000.00
Trucking	1,000.00
Disposal Fees	200.00
Earthwork	85,268.00
Scarifying/Seeding	9,240.00
Mulching/Crimping	3,190.00
TOTAL	$ 135,142.00

PERIOD DESCRIPTION AND COST EXPLANATIONS: Phase IV

Phase IV of the surface reclamation activities is for the backfilling and recontouring of the evaporation ponds, ripping or discing and spreading of topsoil in the pond/plant area, scarifying as needed in the well field, and seeding and mulching the disturbed areas. Additionally, any trash remaining in the permit area will be removed and the well field and plant area fencing will be repaired as needed. Phase IV will last one month.

The earthwork consists of ripping or discing the pond bottoms and parking areas at a cost of $70 per hour for 22 hours ($1,540.00). Fill in ponds using the embankments, at a rate of $1.50 per cubic yard and 32,000 cubic yards for a total of $48,000.00. Re-apply topsoil in ponds area (24,845 cubic yards) at a rate of $1.50 per cubic yard for a total of $37,268.00.

The seed bed preparation involves scarifying the well field access roads and any compacted areas in the well field (66 acres, maximum, times $140 per acre equals $9,240.00). The planting of the 66 acres (not including the cost of seed) is included in the $9,240. Mulching, crimping, and seeding of the areas with new topsoil amounts to $3,190.00.

Seed cost for 88 acres at $138.00 per acre amounts to $12,144.00. Mulch consisting of 50 tons at $50.00 per ton amounts to $2,500.00.

A final radiation check of the site will be made after all topsoil replacement, seeding and mulching has been complete. The cost of the final radiation survey is estimated at $2,000.00.

The trucking and disposal fees are for the hauling of non-radioactive trash to the Gillette land fill (trucking $1,000 and disposal fees $200).

SURFACE RECLAMATION COSTS - PHASE V

EXPENSE ITEM	Amount
CONTRACTOR SITE EXPENSES	
Five Annual Site Inspections	20,000.00
Final Fence Removal	5,000.00
TOTAL	$ 25,000.00

PERIOD DESCRIPTION AND COST EXPLANATION: Phase V

Phase V of the surface reclamation activities is the annual inspection of the North Butte site to check reclamation success. The amount shown includes moneys to annually correct any problems in the revegetation program. This work will be performed by a third party subcontractor. After the reclamation effort has been approved the fence around the well field and plant/ponds area will be removed if the land owner wants it removed.

At the appropriate time during Phase V, depending on how quickly vegetation is re-established on disturbed areas, statistical comparisons of the reclaimed areas to the extended reference areas will be performed as described in Section 17.2. Phase V could last as long as five years.

MATERIALS LICENSE

Pursuant to the Atomic Energy Act of 1954, as amended, the Energy Reorganization Act of 1974 (Public Law 93-438), and Title 10, Code of Federal Regulations, Chapter I, Parts 30, 31, 32, 33, 34, 35, 36, 39, 40, and 70, and in reliance on statements and representations heretofore made by the licensee, a license is hereby issued authorizing the licensee to receive, acquire, possess, and transfer byproduct, source, and special nuclear material designated below; to use such material for the purpose(s) and at the place(s) designated below; to deliver or transfer such material to persons authorized to receive it in accordance with the regulations of the applicable Part(s). This license shall be deemed to contain the conditions specified in Section 183 of the Atomic Energy Act of 1954, as amended, and is subject to all applicable rules, regulations, and orders of the Nuclear Regulatory Commission now or hereafter in effect and to any conditions specified below.

1. Licensee Hydro Resources, Inc. 2929 Coors Blvd, NW Suite 101 Albuquerque, NM 87120	3. License Number: SUA-1508
2.	4. Expiration Date: January 5, 2003
	5. Docket or Reference No.: 40-8968

6. Byproduct, Source, and/or Special Nuclear Material	7. Chemical and/or Physical Form	8. Maximum Amount that Licensee May Possess at Any One Time Under This License
Uranium	Any	Unlimited

SECTION 9: ADMINISTRATIVE CONDITIONS

9.1 The authorized place of use shall be the licensee's Crownpoint Uranium Project which includes the Crownpoint, Unit 1, and Church Rock uranium recovery and processing facilities in McKinley County, New Mexico.

9.2 All written notices and reports required under this NRC license (with the exception of effluent monitoring reports required under License Condition (LC) 12.3 and 10 CFR Part 40.65, which shall also be submitted to Region IV) shall be addressed to the Chief, Uranium Recovery Branch, Division of Waste Management, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Mail Stop T-7J9, Washington, DC 20555. Incidents and events that require telephone notification shall be made to the NRC Operations Center at (301) 816-5100.

9.3 The licensee shall conduct operations in accordance with all commitments, representations, and statements made in its license application submitted by cover letter dated April 25, 1988 (as supplemented by the licensee submittals listed in Attachment A), and in the Crownpoint Uranium Project Consolidated Operations Plan (COP), Rev. 2.0, dated August 15, 1997 - except where superseded by license conditions contained in this license. Whenever the licensee uses the words "will" or "shall" in the aforementioned licensee documents, it denotes an enforceable license requirement.

9.4 A) The licensee may, without prior NRC review or approval: (i) make changes in the Crownpoint Project's facilities or processes as described in the COP (Rev. 2.0); (ii) make changes in its standard operating procedures; and (iii) conduct tests or experiments, if the licensee ensures that the following conditions are met:

(1) the change, test, or experiment does not conflict with any requirement specifically stated in this license, or impair the licensee's ability to meet all applicable NRC regulations;

(2) there is no degradation in the safety or environmental commitments made in the Crownpoint Uranium Project Consolidated Operations Plan (COP), Revision 2.0, or in the approved reclamation plan for the Crownpoint Project; and

(3) the change, test, or experiment is consistent with NRC's findings in NUREG-1508, the Final Environmental Impact Statement (FEIS, dated February 1997) and the Safety Evaluation Report (SER, dated December 1997) for the Crownpoint Project.

If any of these conditions are not met for the change, test, or experiment under consideration, the licensee is required to submit a license amendment application for NRC review and approval. The licensee's determinations as to whether the above conditions are met will be made by a Safety and Environmental Review Panel (SERP). All such determinations shall be documented, and the records kept until license termination. All such determinations shall be reported annually to the NRC, pursuant to LC 12.8. The retained records shall include written safety and environmental evaluations, made by the SERP, that provide the basis for determining whether or not the conditions are met.

B) The SERP shall consist of a minimum of three individuals employed by the licensee, and one of these shall be designated the SERP chairman. One member of the SERP shall have expertise in management and shall be responsible for managerial and financial approval changes; one member shall have expertise in operations and/or construction and shall have responsibility for implementing any operational changes; and, one member shall be the Environmental Manager, with the responsibility of ensuring that changes conform to radiation safety and environmental requirements. Additional members may be included in the SERP as appropriate, to address technical aspects such as health physics, groundwater hydrology, surface-water hydrology, specific earth sciences, and other technical disciplines. Temporary members or permanent members, other than the three above-specified individuals, may be consultants.

9.5 As a prerequisite to operating under this license, the licensee shall submit an NRC-approved surety arrangement to cover the estimated costs of decommissioning, reclamation, and groundwater restoration. Generally, these surety amounts shall be determined by the NRC based on cost estimates for a third party completing the work in case the licensee defaults. Surety for groundwater restoration of the initial well fields shall be based on 9 pore-volumes. Surety shall be maintained at this level until the number of pore volumes required to restore the groundwater quality of a production-scale well field has been established by the restoration demonstration described in LC 10.28. If at any time it is found that well field restoration requires greater pore-volumes or higher restoration costs, the value of the surety will be adjusted upwards. Upon NRC approval, the licensee shall maintain the NRC-approved financial surety arrangement consistent with 10 CFR Part 40, Appendix A, Criterion 9.

Annual updates to the surety amount, required by 10 CFR Part 40, Appendix A, Criterion 9, shall be provided to the NRC at least 3 months prior to the anniversary date of the license issuance. If the NRC has not approved a proposed revision 30 days prior to the expiration date of the existing surety arrangement, the licensee shall extend the existing arrangement, prior to expiration, for 1 year. Along with each proposed revision or annual update of the surety the licensee shall submit supporting documentation showing a breakdown of the costs and the basis for the cost estimates with adjustments for inflation (i.e., using the approved Urban Consumer Price Index), maintenance of a minimum 15 percent contingency, changes in engineering plans, activities performed, and any other conditions affecting estimated costs for site closure.

The licensee shall provide an NRC-approved updated surety before undertaking any planned expansion or operational change which has not been included in the annual surety update. This surety update shall be provided to the NRC at least 90 days prior to the commencement of the planned expansion or operational change.

The licensee shall also provide the NRC with copies of surety-related correspondence submitted to the State of New Mexico, a copy of the State's surety review, and the final approved surety arrangement. The licensee must also ensure that the surety, where authorized to be held by the State, identifies the NRC-related portion of the surety and covers the above-ground decommissioning and decontamination, the cost of off-site disposal, soil and water sample analyses, and groundwater restoration activities associated with the site. The basis for the cost estimate is the NRC-approved site closure plan or the NRC-approved revisions to the plan.

9.6 The licensee shall dispose of 11e.(2) byproduct material from the Crownpoint Project at a waste disposal site licensed by the NRC or an Agreement State to receive 11e.(2) byproduct material. At each project site, the licensee shall maintain an area within the restricted area boundary for storing contaminated materials prior to their disposal. The licensee's approved waste disposal agreement must be maintained on-site. Should this agreement expire or be terminated, the licensee shall notify the NRC pursuant to LC 12.6. A new agreement shall be ratified within 90 days of expiration or termination of the previous agreement, or the licensee will be prohibited from further lixiviant injection.

9.7 The licensee shall implement and maintain a training program for all site employees as described in Regulatory Guide 8.31, and as detailed in the COP of the approved license application. All training materials shall incorporate the information from current versions of 10 CFR Part 19 and 10 CFR Part 20. Additionally, classroom training shall include the subjects described in Section 2.5 of Regulatory Guide 8.31. All personnel shall attend annual refresher training, and the licensee shall conduct regular safety meetings on at least a bi-monthly basis, as described in Section 2.5 of Regulatory Guide 8.31

The Radiation Safety Officer (RSO), or his designee, shall have the education, training and experience as specified in Regulatory Guide 8.31. A Radiation Safety Technician (RST) shall have the qualifications specified in Regulatory Guide 8.31. Any person newly hired as an RST shall have all work reviewed and approved by the RSO as part of a comprehensive training program until appropriate course training is completed, and at least for 6 months from the date of appointment.

9.8 Written standard operating procedures (SOPs) shall be established and followed for: (1) all operational activities involving radioactive materials that are handled, processed, stored, or transported by employees; (2) all non-operational activities involving radioactive materials including in-plant radiation protection and environmental monitoring; and (3) emergency procedures for potential accident/unusual occurrences including significant equipment or facility damage, pipe breaks and spills, loss or theft of yellowcake or sealed sources, and significant fires. The SOPs shall include appropriate radiation safety practices to be followed in accordance with 10 CFR Part 20. SOPs for operational activities shall enumerate pertinent radiation safety practices to be followed. A copy of the current written procedures shall be kept in the area(s) of the production facility where they are utilized. All SOPs for activities described in the COP shall be reviewed and approved as presently described in the COP.

9.9 Release of equipment, materials, or packages from the restricted area shall be in accordance with NRC staff position, "Guidelines for Decontamination of Facilities and Equipment Prior to Release for Unrestricted Use or Termination of Licenses for Byproduct or Source Materials,"

G) specific details on the design, construction, maintenance, and operation of the waste retention ponds and embankments (where applicable);

H) specific details on the design, construction, maintenance, and operation of the liners and leak detection system.

I) any other analyses and computations which demonstrate that applicable design criteria have been met.

10.27 Prior to the injection of lixiviant at the Crownpoint site, the licensee shall:

A) Replace the town of Crownpoint's water supply wells NTUA-1, NTUA-2, BIA-3, BIA-5, and BIA-6, construct the necessary water pipeline, and provide funds so the existing water supply systems of the Navajo Tribal Utility Authority (NTUA) and the Bureau of Indian Affairs (BIA) can be connected to the new wells. Any new wells, pumps, pipelines, and other changes to the existing water supply systems, made necessary by the replacement of the wells specified above, shall be made such that the systems can continue to provide at least the same quantity of water as the existing systems. The new wells shall be located so that the water quality at each individual well head does not exceed the EPA's primary and secondary drinking water standards, and does not exceed a concentration of 0.44 mg/L (300 pCi/L) uranium, as a result of *in situ* leach uranium extraction activities at the Unit 1 and Crownpoint sites. To determine the appropriate placement of the new wells, the licensee shall coordinate with the appropriate agencies and regulatory authorities, including BIA, NTUA, the Navajo Nation Department of Water Development and Water Resources, and the Navajo Nation EPA.

B) Abandon and seal wells NTUA-1, NTUA-2, BIA-3, BIA-5, and BIA-6 in accordance with applicable requirements so these wells cannot become future pathways for the vertical movement of contaminants.

10.28 Prior to the injection of lixiviant at either the Unit 1 or Crownpoint site, the licensee shall submit NRC-approved results of a groundwater restoration demonstration conducted at the Church Rock site. The demonstration shall be conducted on a large enough scale, acceptable to the NRC, to determine the number of pore volumes that shall be required to restore a production-scale well field.

10.29 Before starting uranium extraction operations beyond the first well field at the Church Rock site, the licensee shall submit an NRC-approved groundwater restoration plan for the entire project. At a minimum, this plan shall include: (a) a proposed restoration schedule; (b) a general description of the restoration methodology; and (c) a description of post-restoration groundwater monitoring.

10.30 Prior to injecting lixiviant at any of the sites, the licensee shall submit an NRC-approved procedure-level, detailed effluent and environmental monitoring program. In addition, the licensee shall develop and administer its radiological effluent and environmental monitoring program consistent with Regulatory Guide 4.14. The licensee shall maintain, at a minimum, three airborne effluent monitoring stations at each site, at the locations described in COP (Rev.2.0) Table 9.5-1.

10.31 Prior to the injection of lixiviant at the Church Rock site, the licensee shall conduct a Westwater Canyon aquifer step-rate injection (fracture) test within the Church Rock site boundaries, but outside future well field areas. One such test at the Unit 1 or Crownpoint site shall also be performed before lixiviant injection begins at either of these sites.

ADDITIONAL INFORMATION REQUEST
HYDRO RESOURCES, INC. IN-SITU LEACH URANIUM MINE
CROWNPOINT, NEW MEXICO

ISSUE: Cost/Benefit Analysis

Comments Applicable to
UNIT 1-Site

92.

Discussion - The applicant provided much of the information necessary to conduct a cost/benefit analysis of the proposed project in the license application and supporting materials. However, staff need additional information to conduct cost/benefit analyses of alternatives to the proposed project and to make an economic comparison between the proposed project and alternatives.

Action Needed: Provide the investment costs and operating costs for the life cycle of each alternative described in the Description of Proposed Action and Alternatives (DOPAA, see Enclosure 2), including the proposed project. Provide the costs by major category (e.g., capital costs, operating costs) and by subcategory (e.g., land, labor, equipment, buildings, improvements such as roads, taxes, well production, restoration, reclamation, decommissioning, monitoring) for each major category. For each alternative, discuss and quantify the major causes of cost uncertainty. Provide a time profile of costs over the life cycle of each alternative so that costs can be discounted (i.e., provide information on when costs would occur relative to the beginning of the project).

Provide projected revenues for the life cycle of each alternative described in the DOPAA, including the proposed project. Discuss the uncertainty in revenues associated with each alternative and describe the factors that affect uncertainty (e.g., market conditions, quality of the product). Provide a time profile of revenues over the life cycle of each alternative so that revenues can be discounted and compared to costs.

Based on the cost and revenue information described above, evaluate and compare the life-cycle profitability and financial feasibility of each alternative, including the proposed project.

Response

Full cycle feasibility studies were compiled for each of the three New Mexico projects proposed by Hydro Resources, Inc. (HRI). Each study's economics is divided into five major cost categories. These categories include: Plant Capital, Wellfield Replacement Capital, Plant Operating Expense, Wellfield Operating Expense and Restoration and Reclamation. Each major category is further subdivided into costing classifications from which the company's accounting code is derived.

There are approximately 150 individual classifications contained within this set of codes which has demonstrated its effectiveness in budgeting over the past decade. This set of codes are further classified into eleven areas. They include: labor, auxiliary costs, environmental, well completion costs, chemicals, electrical, wellfield hardware maintenance, plant hardware maintenance, ancillary plant costs, yellowcake drying and handling, and vehicles.

Labor costs (subcodes 1-8) include all labor, hourly and salary assigned to the project. Auxiliary costs (subcodes 9-88, 100) consist of various fixed and variable costs associated with managing that portion of the project. They include: telephone, copier, licenses, travel, rental, ad valorem tax, insurance, postage, freight, advertising, legal, office supplies, and safety. Environmental costs (subcodes 90-99) contain charges associated

with routine monitoring, well plugging, and decommissioning/decontamination. Well completion costs (subcodes 101-127) consider all aspects and materials needed to drill and complete monitor, injection, and production wells. Chemicals (subcodes 190-210) needed for the recovery and mining process include; oxygen, hydrochloric acid, hydrogen peroxide, caustic, ion exchange resins, brine (NaCl), and biocides (Zn and Cu sulphates). Electrical cost (subcode 211) is a major cost component of production which is reported separately. Wellfield maintenance hardware costs (subcodes 220-230) contains all costs affiliated with the operations of an operating wellfield. These include; submersible pumps and motor, field piping and valves, oxygen delivery equipment, water meters, electrical panels and cables, and miscellaneous charges. Plant hardware maintenance (subcodes 250-260) include operation items necessary for the continuing processing of mine waters, and their mineral values, within the plant area. Such items include; pumps, tanks, instrumentation, plant electrical, filters, steel, and miscellaneous items. Ancillary plant costs (subcodes 261-275) comprise areas outside to immediate processing area. These areas include; roads, disposal (brine concentrator/disposal well) pipelines, gas, oil, reverse osmosis lab supplies, plant office equipment and furniture. Yellowcake drying and handling charges (subcodes 280-286) contain those costs with the processing, shipment, transportation, and fees related to shipping finished uranium oxide product. Finally, vehicles charges (subcodes 290-405) are defined. These charges include the maintenance of, and purchase costs for all mobile equipment required at the project.

For each category of operations (plant capital, wellfield replacement capital, etc.) a detailed monthly listing containing all subcodes detailed above, is presented for each or HRI's New Mexico projects, which provides corporate management a schedule of construction, mining, and restoration/reclamation. Marketing utilizes the estimated production rates and costs to gauge contract requirements and pricing. The company enters into long-term guaranteed contracts with domestic nuclear utilities based on this data.

Feasibility Model

The feasibility model is a projection of costs that a company would incur throughout the life of the project being studied. Geological, hydrological, ore kinetics, and processing equipment information are required to forecast estimated production rates, capital and operating costs, and staffing to insure a reasonable mining and permitting schedule. Exhaustive site and area information has been compiled and is contained within each project's feasibility study. With this information, plant and wellfield sizes can be designed to meet the specifications of the property.

Plant Capital Details

Each processing facility is designed to be a downflow ion exchange operation. A comprehensive cost tabulation, that utilizes cost details contained on a separate equipment specification sheet, is basis for the plant capital costs. All major items for the recovery facility have been specified and priced in 1996 dollars. These specific item charges are contained on the tabulation sheet opposite its chargeable subcode and month for which the equipment will be sited. Pumps, tanks, ion-exchange resins, brine concentrator, reverse osmosis, vehicles, piping and valves, filters, synthetic double-lined ponds, concrete, buildings, lab supplies, computers, and miscellaneous fixed costs (phone, electrical, postage, ad valorem tax, insurances, etc.) are all accounted for and contained on this report. Labor is detailed by job description at the heading of each month. This provides the basis for estimating the wages, salaries, insurance, and taxes applied.

Wellfield Replacement Capital

The second section of the feasibility assesses the work required to drill, complete and develop wells for the mining process. Comparable to the plant capital details, a cost listing of individual components associated with each type of well completion is detailed on the sheet titled Well Details. Each component bears a subcode to which the item is charged. The rate at which drilling progresses is based on the need to replace mined out reserves. Decline curves, which approximate the rate for which mining is expected, is detailed for each ore sand based on its average open interval of thickness, ore grade, tonnage factor, recovery factor, porosity, areal extent, and lixiviant circulation. This provides the company with the anticipate time required to mine various segments of the ore

deposit classified as "wellfields". All development costs chargeable to this segment are tallied in the same way that charges were assessed in the preceding plant capital details section.

Plant Operations Details

Plant operations commence upon completion of the first group of Class III wells and the recovery plant. Flowrate through the plant is based on the number of projected instantaneously operating production wells. As these wells deplete in uranium values, new operating wells are brought on-line for their replacement. This insures efficiency and maximization of the capital. The process of well replacement is replicated throughout the operating life of the project and becomes a function of the Wellfield Replacement tabulation.

All costs associated with the loading, eluting, precipitation,, filtering, drying, and packaging are charged to the project from which the uranium was recovered. These costs are contained within each study even though the actual precipitation, filtering, and drying might not occur at the project site of genesis. The Nuclear Regulatory Commission has requested that separate feasibilities be developed to forecast cost sensitivities of the following conditions:

1. Haul loaded resin to an adjoining HRI project site; i.e., Churchrock, Crownpoint, or Unit 1.

2. Ship yellowcake slurry to a centeralized drying facility at one of HRI's project sites.

3. Ship yellowcake slurry to URI's Kingsville Dome project for drying.

4. Each project is a stand alone unit where precipitation, filtering, drying and packaging is achieved.

Table I is a tabulation of all 12 cases.

	Churchrock	Crownpoint	Unit I
Haul Loaded Resin	$11.36	$9.46	$10.46
Ship Yellowcake Slurry	$11.32	$9.40	$10.48
Ship Yellowcake Slurry to Texas	$11.83	$9.87	$11.05
Stand Alone Project	$11.30	$9.38	$10.51

The lowest cost for each project is the stand alone case, except of Unit 1. Unit 1's total transportation costs for the 8 miles round-trip between Unit 1 and Crownpoint does not exceed the installation costs for all the needed equipment to facilitate elution precipitation, filtering, drying, and packaging. Transportation costs for the other projects exceeded the capital required for this same equipment.

Shipping yellowcake slurry to Kingsville, Texas requires the installation of another vacuum dryer at URI's Kingsville Dome project as that dryer is dedicated for URI's Rosita and Kingsville Dome projects.

The Plant Operating Details tabulations includes a section near the beginning that calculates the number of resin or yellowcake slurry trips for each month's projected production. Shipping to Kingsville for drying would require slurry storage tanks at each New Mexico project to handle the surges in production. This correspondingly would retard making timely deliveries of dried material to the customer. The distance from Gallup to Kingsville is approximately 1,175 miles transversing though Albuquerque, New Mexico and San Antonio, Texas.

Hauling resin from one HRI New Mexico project site to another will aid employment in the area for professional truck drivers, as in all instances, multiple daily resin trailer transfers will be required.

All costs associated with the integral operation of the recovery plant are inclusive in this section of the feasibility. Chemical and electrical demands and projected price are detailed on the Chemical Detail sheet.

Wellfield Operating Details

All charges for operating the wellfield department are tallied in this section of the report. many costs are pro-rated on the number of operating wells or the flow produced from the wellfield. Again, as in the other sections that make up the overall feasibility, fixed and variable costs have been assigned accordingly.

Sustaining flowrates through the ion exchange recovery plant, new wells are brought into production as required. Depleted wells are shut-in prior to being placed into restoration. Restoration is scheduled to commence shortly after mining in defined areas has ceased.

Restoration and Reclamation

The Restoration and Reclamation schedule provides a restoration fluid balance based on circulating four pore volumes of processed water through the mine-out reservoir. In each of the twelve cases provided. a brine concentrator has been employed to treat brine generated from a reverse osmosis unit. Restoration waters are first introduced to ion exchange to remove any trace amounts of uranium. The solutions are then "ionically filtered" using reverse osmosis. The larger purified volume portion is returned to the wellfield area and reinjected. Brine generated from the reverse osmosis process is "distilled" inside a brine generator thereby producing additional quantities of pure water for wellfield injection. The resulting slurry rejected by the brine generator is very small in overall volume. It is directed to double-lined hypolan ponds for storage. The solids will later be transferred to an approved site.

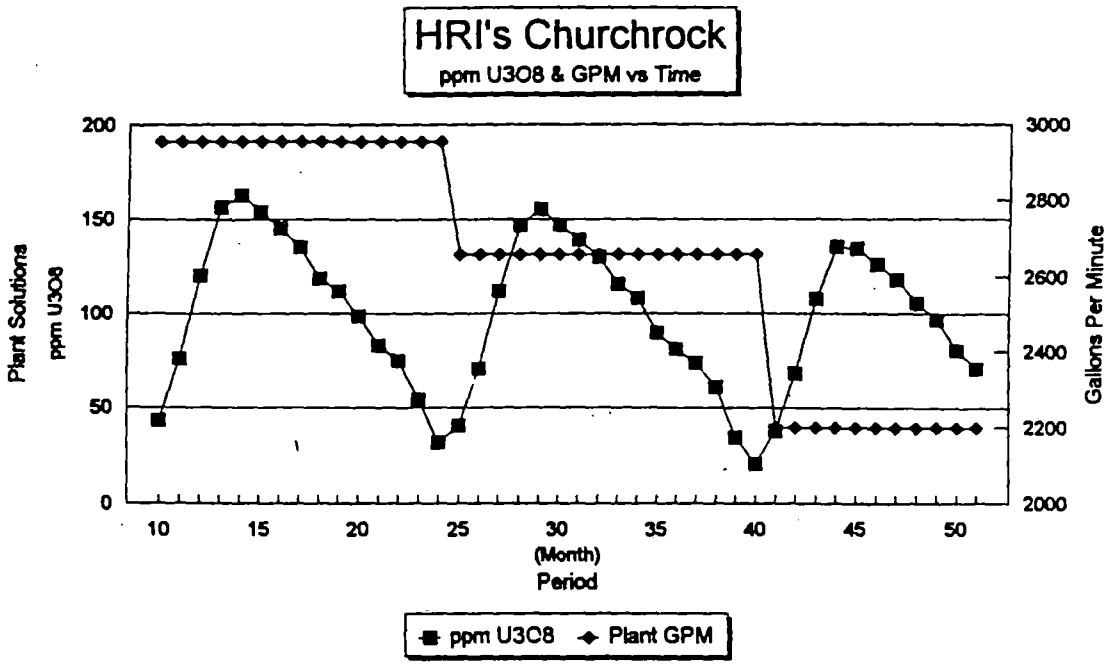
All costs associated with the pumping, treatment of wellfield solutions are accounted. Plugging of all production wells occurs 15 months after restoration for selected areas have been achieved. Just prior to the last wellfield plugging. reclamation of the surface recovery structure commences.

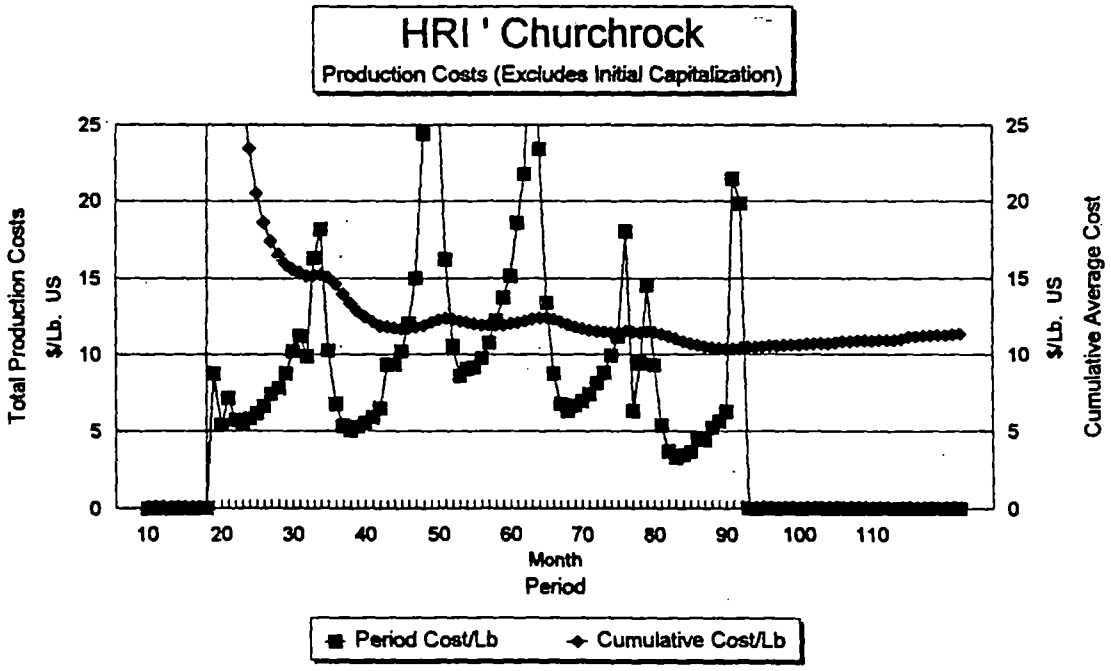
Conclusion

Each feasibility is very complete and addresses each question from the NRC contained within their Question 92. A discussion on the future of the uranium market can not be provided by this author. I believe history has demonstrated that there are no accurate and true market forecasters. Based on other uranium projects. the author has evaluated over the past 20 years, the properties controlled by HRI are expansive, average grade of ore is high, and the full cycle economics make them one of the lowest-cost deposits in the United States.

CHURCH ROCK HAUL RESIN SUMMARY

Haul Loaded Resin Summary





Full Cycle Project Costs = $11.36 /Lb. U3O8

otal Employment			.8	38.05	38[redacted]	38.05	38.05	38.05	38.05	1.05
Period	Averages or Totals		1	2	3	4	5	6	7	8
# Injection Wells	834		0.0	0.0	28.3	28.3	28.3	28.3	28.3	28.3
# Extraction Wells	868		0.0	0.0	32.7	32.7	32.7	32.7	32.7	32.7
# Monitor Wells	80		0.0	37.0	0.0	6.0	0.0	0.0	0.0	0.0
# Definite Wells	958		0.0	19.9	32.8	36	32.8	32.8	32.8	32.8
# Plugged Holes	0		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# of Rigs Required			0.0	3.2	4.5	5.0	4.5	4.5	4.5	4.5
Operating Wells										
# Injection Wells			0	0	0	0	0	0	0	0
# Extraction Wells			0	0	0	0	0	0	0	0
Production										
PPM	95.92		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GPM	2,634		0	0	0	0	0	0	0	0
Pounds U3O8	6,736,265		0	0	0	0	0	0	0	0
Period Cost, $/Lb.			NA	NA	NA	NA	NA	NA	NA	NA
Cumulative Cost/Cumulative Production, $/Lb.	$11.36		NA	NA	NA	NA	NA	NA	NA	NA

Project Cost Summary		$/Lb.		%							
1 - 8	Labor	$3.02	$20,359,543	26.6%	$100,652	$112,131	$112,131	$112,131	$112,131	$112,131	$112,131	$119,714
9 - 88, 100	Auxiliary Costs	$0.37	$2,511,034	3.3%	$41,284	$22,376	$79,701	$21,751	$21,751	$35,751	$21,751	$21,863
90 - 99	Environmental	$0.25	$1,661,341	2.2%	$0	$0	$0	$0	$0	$0	$0	$0
101 - 127	Well Completion Costs	$2.89	$19,496,564	25.5%	$500	$375,278	$575,558	$636,333	$575,558	$575,558	$575,558	$575,558
190 - 210	Chemicals	$0.90	$6,057,807	7.9%	$0	$0	$0	$0	$0	$0	$0	$0
211 - 212	Electrical & Water	$0.86	$5,813,610	7.6%	$45,400	$1,200	$1,200	$1,200	$1,200	$1,200	$1,200	$1,200
220 - 230	Wellfield Hardware Maintenance	$1.32	$8,912,802	11.6%	$37,000	$22,000	$198,904	$198,904	$198,904	$198,904	$198,904	$198,904
250 - 260	Plant Hardware Maintenance	$0.28	$1,886,032	2.5%	$50,600	$57,933	$296,943	$327,417	$454,054	$150,180	$84,133	$24,300
261 - 275	Ancillary Plant Costs	$0.81	$5,460,389	7.1%	$153,227	$289,071	$139,444	$168,027	$417,687	$204,403	$226,981	$786,400
280 - 286	Yellowcake Drying and Handling	$0.37	$2,474,141	3.2%	$0	$0	$0	$0	$0	$0	$0	$0
290 - 406	Vehicle Charges	$0.28	$1,873,160	2.4%	$297,700	$403,750	$78,150	$6,150	$6,150	$6,150	$6,150	$546,150
	Totals	$11.36	$76,508,313	100%	$726,362	$1,283,739	$1,482,032	$1,471,913	$1,787,435	$1,284,278	$1,226,808	$2,274,089
	Cumulative Totals				$0.726	$2.010	$3.492	$4.964	$6.751	$8.036	$9.263	$11.537
	Plant Capital & Elution/Drying	$0.99	$6,651,661	8.7%	$390,164	$532,512	$569,821	$533,627	$909,924	$406,767	$166,917	$1,398,778
	Wellfield Replacement Capital	$4.78	$32,213,314	42.1%	$336,199	$751,227	$912,211	$938,286	$877,511	$877,511	$1,059,892	$875,311
	Plant Operating Expense	$2.64	$17,791,883	23.3%	$0	$0	$0	$0	$0	$0	$0	$0
	Wellfield Operating Expense	$1.43	$9,629,525	12.6%	$0	$0	$0	$0	$0	$0	$0	$0
	Restoration & Decommissioning	$1.52	$10,221,930	13.4%	$0	$0	$0	$0	$0	$0	$0	$0
	Totals	$11.36	$76,508,313	100%	$726,362	$1,283,739	$1,482,032	$1,471,913	$1,787,435	$1,284,278	$1,226,808	$2,274,089
	Cumulative Totals				$726	$2,010	$3,492	$4,964	$6,751	$8,036	$9,263	$11,537

	Total Employment	46.55	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
	Period	9	10	11	12	13	14	15	16	17	18	19
	# Injection Wells	0.0	0.0	0.0	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7
	# Extraction Wells	0.0	0.0	0.0	17.6	17.6	17.6	17.6	17.6	17.6	17.6	17.6
	# Monitor Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	1.0	1.0	1.0
	# Definite Wells	0.0	0.0	0.0	18.5	18.5	18.5	18.5	19.0	19.0	19.0	19.0
	# Plugged Holes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	# of Rigs Required	0.0	0.0	0.0	2.6	2.6	2.6	2.6	2.6	2.6	2.6	2.6
	Operating Wells											
	# Injection Wells	0	170	170	170	170	170	170	170	198	198	198
	# Extraction Wells	0	196	196	196	196	196	196	196	229	229	229
	Production											
	PPM	0.0	43.3	75.9	120.6	156.5	162.8	154.0	145.6	135.6	118.8	112.2
	GPM	0	2,956	2,956	2,956	2,956	2,956	2,956	2,956	2,956	2,956	2,956
	Pounds U3O8	0	46,779	81,948	130,220	168,934	175,779	166,308	157,217	146,368	128,282	121,152
	Period Cost, $/Lb.	NA	$8.75	$5.37	$7.16	$5.72	$5.53	$5.80	$6.15	$6.59	$7.39	$7.78
	Cumulative Cost/Cumulative Production, $/Lb.	NA	$294.11	$110.29	$58.43	$37.62	$28.27	$23.42	$20.49	$18.59	$17.40	$16.52

Project Cost Summary												
1 - 8	Labor	$134,746	$177,904	$177,904	$177,904	$177,904	$177,904	$178,477	$178,477	$178,477	$178,477	$178,477
9 - 88, 100	Auxiliary Costs	$22,864	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414
90 - 99	Environmental	$0	$250	$250	$250	$250	$250	$250	$250	$250	$250	$250
101 - 127	Well Completion Costs	$500	$12,180	$12,180	$336,218	$336,218	$336,218	$336,218	$346,348	$346,348	$346,348	$346,348
190 - 210	Chemicals	$675,640	$51,186	$68,533	$92,343	$111,438	$114,814	$110,142	$105,658	$100,307	$91,386	$87,870
211 - 212	Electrical & Water	$1,200	$61,758	$61,758	$61,758	$61,758	$61,758	$61,758	$61,758	$61,758	$61,758	$61,758
220 - 230	Wellfield Hardware Maintenance	$4,000	$46,136	$46,136	$152,738	$152,738	$152,738	$152,738	$152,738	$159,761	$159,761	$159,761
250 - 260	Plant Hardware Maintenance	$45,800	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705
261 - 275	Ancillary Plant Costs	$918,200	$12,580	$12,580	$33,198	$33,198	$33,198	$33,198	$33,198	$33,198	$33,198	$33,198
280 - 286	Yellowcake Drying and Handling	$2,800	$17,162	$30,064	$47,774	$61,977	$64,488	$61,014	$57,678	$53,698	$47,063	$44,447
290 - 405	Vehicle Charges	$6,150	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200	$3,200
	Totals	$1,811,900	$409,475	$439,724	$932,502	$965,800	$971,687	$964,114	$966,424	$964,115	$948,559	$942,427
	Cumulative Totals	$13,349	$13,758	$14,198	$15,130	$16,096	$17,068	$18,032	$18,998	$19,962	$20,911	$21,853
	Plant Capital & Elution/Drying	$1,743,151	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Wellfield Replacement Capital	$68,749	$68,749	$68,749	$520,007	$520,007	$520,007	$520,560	$530,709	$530,709	$530,709	$530,709
	Plant Operating Expense	$0	$211,417	$241,666	$283,186	$316,484	$322,371	$314,225	$306,405	$297,074	$281,518	$275,386
	Wellfield Operating Expense	$0	$129,309	$129,309	$129,309	$129,309	$129,309	$129,309	$129,309	$136,332	$136,332	$136,332
	Restoration & Decommissioning	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Totals	$1,811,900	$409,475	$439,724	$932,502	$965,800	$971,687	$964,114	$966,424	$964,115	$948,559	$942,427
	Cumulative Totals	$13,349	$13,758	$14,198	$15,130	$16,096	$17,068	$18,032	$18,998	$19,962	$20,911	$21,853

Total Employment	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8	63.8
Period	20	21	22	23	24	25	26	27	28	29	30
# Injection Wells	16.7	16.7	16.7	0.0	0.0	10.5	10.5	10.5	10.5	10.5	10.5
# Extraction Wells	17.6	17.6	17.6	0.0	0.0	9.9	9.9	9.9	9.9	9.9	9.9
# Monitor Wells	1.0	1.0	1.0	15.0	15.0	0.0	0.0	0.0	0.0	0.0	0.0
# Definite Wells	19.0	19.0	19.0	8.1	8.1	11.0	11.0	11.0	11.0	11.0	11.0
# Plugged Holes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# of Rigs Required	2.6	2.6	2.6	1.3	1.3	1.5	1.5	1.5	1.5	1.5	1.5
Operating Wells											
# Injection Wells	198	198	198	198	215	246	246	246	246	217	217
# Extraction Wells	229	229	229	229	246	262	262	262	262	229	229
Production											
PPM	98.7	82.9	74.9	54.4	31.9	40.6	70.4	112.1	147.1	155.6	147.1
GPM	2,956	2,956	2,956	2,956	2,956	2,659	2,659	2,659	2,659	2,659	2,659
Pounds U3O8	106,617	89,554	80,877	58,733	34,493	39,429	68,398	108,833	142,830	151,137	142,909
Period Cost, $/Lb.	$8.72	$10.22	$11.22	$9.86	$16.30	$18.15	$10.24	$6.76	$5.35	$5.06	$5.30
Cumulative Cost/Cumulative Production, $/Lb.	$15.94	$15.60	$15.38	$15.18	$15.21	$15.27	$15.08	$14.61	$13.96	$13.35	$12.86

Project Cost Summary

1 - 8	Labor	$178,477	$178,477	$178,477	$178,477	$178,477	$178,477	$178,477	$178,477	$178,477	$178,477	$178,477
9 - 88, 100	Auxiliary Costs	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414	$24,414
90 - 99	Environmental	$250	$250	$250	$250	$250	$250	$250	$250	$250	$250	$250
101 - 127	Well Completion Costs	$346,348	$346,348	$346,348	$164,117	$164,117	$204,613	$204,613	$204,613	$204,613	$204,613	$204,613
190 - 210	Chemicals	$80,700	$72,284	$68,005	$57,083	$45,126	$44,737	$59,025	$76,969	$95,738	$99,835	$95,777
211 - 212	Electrical & Water	$61,758	$61,758	$61,758	$61,758	$61,758	$55,554	$55,554	$55,554	$55,554	$55,554	$55,554
220 - 230	Wellfield Hardware Maintenance	$159,761	$159,761	$159,761	$53,159	$57,047	$122,345	$122,345	$122,345	$122,345	$115,322	$115,322
250 - 260	Plant Hardware Maintenance	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705
261 - 275	Ancillary Plant Costs	$33,198	$33,198	$33,198	$12,580	$12,580	$24,820	$24,820	$24,820	$24,820	$24,820	$24,820
280 - 286	Yellowcake Drying and Handling	$39,115	$32,855	$29,671	$21,548	$12,654	$14,465	$25,093	$39,928	$52,400	$55,448	$52,429
290 - 405	Vehicle Charges	$3,200	$3,200	$3,200	$3,200	$3,200	$43,200	$3,200	$3,200	$3,200	$3,200	$3,200
	Totals	$929,925	$915,249	$907,786	$579,290	$562,329	$715,581	$700,497	$735,275	$764,516	$764,638	$757,562
	Cumulative Totals	$22,783	$23,699	$24,606	$25,186	$25,748	$26,464	$27,164	$27,899	$28,664	$29,428	$30,186
	Plant Capital & Elution/Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Wellfield Replacement Capital	$530,709	$530,709	$530,709	$221,259	$221,259	$334,764	$334,764	$334,764	$334,764	$334,764	$334,764
	Plant Operating Expense	$262,884	$248,208	$240,745	$221,699	$200,850	$197,586	$222,502	$257,261	$286,521	$293,666	$286,590
	Wellfield Operating Expense	$136,332	$136,332	$136,332	$136,332	$140,221	$183,231	$143,231	$143,231	$143,231	$136,208	$136,208
	Restoration & Decommissioning	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Totals	$929,925	$915,249	$907,786	$579,290	$562,329	$715,581	$700,497	$735,275	$764,516	$764,638	$757,562
	Cumulative Totals	$22,783	$23,699	$24,606	$25,186	$25,748	$26,464	$27,164	$27,899	$28,664	$29,428	$30,186

Total Employment	63.8	63.8	63.8	63.8	63.8	63.8	71.8	71.8	71.8	71.8	71.8
Period	31	32	33	34	35	36	37	38	39	40	41
# Injection Wells	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	12.8	12.8
# Extraction Wells	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	12.9	12.9
# Monitor Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Definite Wells	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	13.8	13.8
# Plugged Holes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# of Rigs Required	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.9	1.9
Operating Wells											
# Injection Wells	217	217	217	217	217	201	184	184	184	184	158
# Extraction Wells	229	229	229	229	229	212	194	194	194	194	148
Production											
PPM	139.5	130.3	115.9	108.6	89.6	80.8	73.5	60.8	34.8	20.9	37.9
GPM	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,659	2,199
Pounds U3O8	135,466	126,574	112,612	105,492	87,063	78,474	71,373	59,098	33,794	20,315	30,469
Period Cost, $/Lb.	$5.55	$5.87	$6.50	$9.31	$9.34	$10.22	$12.06	$14.99	$24.38	$45.45	$28.52
Cumulative Cost/Cumulative Production, $/Lb.	$12.46	$12.14	$11.91	$11.81	$11.74	$11.70	$11.71	$11.77	$11.90	$12.12	$12.28

Project Cost Summary

1 - 8	Labor	$178,477	$178,477	$178,477	$281,128	$281,128	$281,128	$301,592	$306,152	$306,152	$306,152	$306,152
9 - 88, 100	Auxiliary Costs	$24,414	$24,414	$24,414	$25,336	$25,336	$25,336	$25,689	$25,689	$25,689	$25,689	$25,689
90 - 99	Environmental	$250	$250	$250	$250	$250	$250	$650	$650	$650	$650	$650
101 - 127	Well Completion Costs	$204,613	$204,613	$204,613	$204,613	$204,613	$204,613	$204,613	$204,613	$204,613	$254,480	$254,480
190 - 210	Chemicals	$92,106	$87,720	$80,833	$77,321	$68,232	$63,995	$63,493	$57,439	$44,958	$38,310	$38,940
211 - 212	Electrical & Water	$55,554	$55,554	$55,554	$55,554	$55,554	$55,554	$82,462	$82,462	$82,462	$82,462	$72,646
220 - 230	Wellfield Hardware Maintenance	$115,322	$115,322	$115,322	$115,322	$115,322	$111,433	$112,265	$112,265	$112,265	$130,102	$121,158
250 - 260	Plant Hardware Maintenance	$2,705	$2,705	$2,705	$2,705	$2,705	$2,705	$12,205	$3,205	$3,205	$3,205	$3,205
261 - 275	Ancillary Plant Costs	$24,820	$24,820	$24,820	$136,500	$24,820	$24,820	$28,320	$28,320	$28,320	$31,495	$31,495
280 - 286	Yellowcake Drying and Handling	$49,698	$46,436	$41,314	$38,702	$31,941	$28,790	$26,185	$21,681	$12,396	$7,453	$11,178
290 - 405	Vehicle Charges	$3,200	$3,200	$3,200	$43,200	$3,200	$3,200	$3,300	$43,300	$3,300	$43,300	$3,300
	Totals	$751,159	$743,512	$731,503	$982,632	$813,101	$801,825	$860,774	$885,777	$824,012	$923,298	$869,093
	Cumulative Totals	$30,937	$31,681	$32,412	$33,395	$34,208	$35,010	$35,871	$36,756	$37,580	$38,504	$39,373
	Plant Capital & Elution/Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Wellfield Replacement Capital	$334,764	$334,764	$334,764	$552,017	$438,337	$438,337	$438,337	$438,337	$438,337	$509,216	$509,216
	Plant Operating Expense	$280,188	$272,540	$260,531	$254,407	$238,556	$231,188	$225,061	$214,504	$192,739	$181,146	$178,239
	Wellfield Operating Expense	$136,208	$136,208	$136,208	$176,208	$136,208	$132,320	$128,431	$168,431	$128,431	$168,431	$117,133
	Restoration & Decommissioning	$0	$0	$0	$0	$0	$0	$68,946	$64,506	$64,506	$64,506	$64,506
	Totals	$751,159	$743,512	$731,503	$982,632	$813,101	$801,825	$860,774	$885,777	$824,012	$923,298	$869,093
	Cumulative Totals	$30,937	$31,681	$32,412	$33,395	$34,208	$35,010	$35,871	$36,756	$37,580	$38,504	$39,373

62

Total Employment	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8
Period	42	43	44	45	46	47	48	49	50	51	52
# Injection Wells	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8	12.8
# Extraction Wells	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9	12.9
# Monitor Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Definite Wells	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8	13.8
# Plugged Holes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# of Rigs Required	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
Operating Wells											
# Injection Wells	158	158	158	158	158	158	158	158	158	158	158
# Extraction Wells	148	148	148	148	148	148	148	148	148	148	148
Production											
PPM	68.3	108.1	135.8	134.5	126.4	118.0	105.9	96.8	80.5	70.8	63.8
GPM	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199	2,199
Pounds U3O8	54,835	86,824	109,082	108,046	101,506	94,796	85,061	77,721	64,665	56,877	51,226
Period Cost, $/Lb.	$16.23	$10.57	$8.59	$9.03	$9.17	$9.76	$10.77	$12.22	$13.73	$15.15	$18.57
Cumulative Cost/Cumulative Production, $/Lb.	$12.34	$12.30	$12.18	$12.08	$12.00	$11.95	$11.92	$11.93	$11.96	$12.00	$12.08

Project Cost Summary

1 - 8	Labor	$306,152	$306,152	$306,152	$306,152	$306,152	$306,152	$306,152	$306,152	$306,152	$306,152	$306,152
9 - 88, 100	Auxiliary Costs	$25,689	$25,689	$25,689	$25,689	$25,689	$25,689	$25,689	$25,689	$25,689	$25,689	$25,689
90 - 99	Environmental	$650	$650	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$55,900
101 - 127	Well Completion Costs	$254,480	$254,480	$254,480	$254,480	$254,480	$254,480	$254,480	$254,480	$254,480	$254,480	$254,480
190 - 210	Chemicals	$50,958	$66,737	$77,715	$77,204	$73,978	$70,668	$65,867	$62,247	$55,807	$51,966	$49,178
211 - 212	Electrical & Water	$72,846	$72,846	$72,846	$72,846	$72,846	$72,846	$72,846	$72,846	$63,729	$47,138	$72,846
220 - 230	Wellfield Hardware Maintenance	$121,158	$121,158	$121,158	$121,158	$121,158	$121,158	$121,158	$121,158	$119,484	$116,437	$121,158
250 - 260	Plant Hardware Maintenance	$3,205	$3,205	$3,205	$3,205	$3,205	$3,205	$3,205	$3,205	$3,205	$3,205	$12,205
261 - 275	Ancillary Plant Costs	$31,495	$31,495	$31,495	$31,495	$31,495	$31,495	$31,495	$31,495	$31,495	$31,495	$31,495
280 - 286	Yellowcake Drying and Handling	$20,118	$31,853	$40,019	$39,639	$37,240	$34,778	$31,206	$28,514	$23,724	$20,867	$18,793
290 - 405	Vehicle Charges	$3,300	$3,300	$3,300	$43,300	$3,300	$3,300	$3,300	$43,300	$3,300	$3,300	$3,300
	Totals	$890,051	$917,565	$937,059	$976,168	$930,543	$924,772	$916,399	$950,086	$888,065	$861,729	$951,197
	Cumulative Totals	$40,263	$41,180	$42,117	$43,094	$44,024	$44,949	$45,865	$46,815	$47,703	$48,565	$49,516
	Plant Capital & Elution/Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Wellfield Replacement Capital	$509,216	$509,216	$509,216	$509,216	$509,216	$509,216	$509,216	$509,216	$509,216	$509,216	$509,216
	Plant Operating Expense	$199,197	$226,711	$245,855	$244,963	$239,338	$233,567	$225,194	$218,881	$207,651	$200,953	$196,092
	Wellfield Operating Expense	$117,133	$117,133	$117,133	$157,133	$117,133	$117,133	$117,133	$157,133	$117,133	$117,133	$117,133
	Restoration & Decommissioning	$64,506	$64,506	$64,856	$64,856	$64,856	$64,856	$64,856	$64,856	$54,065	$34,427	$128,756
	Totals	$890,051	$917,565	$937,059	$976,168	$930,543	$924,772	$916,399	$950,086	$888,065	$861,729	$951,197
	Cumulative Totals	$40,263	$41,180	$42,117	$43,094	$44,024	$44,949	$45,865	$46,815	$47,703	$48,565	$49,516

Total Employment	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	52.5	ERR	ERR
Period	75	76	77	78	79	80	81	82	83	83	85
# Injection Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Extraction Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Monitor Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Definite Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Plugged Holes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# of Rigs Required	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Wells											
# Injection Wells	156	156	156	156	156	156	156	156	156	0	0
# Extraction Wells	162	162	162	162	162	162	162	162	162	0	0
Production											
PPM	144.1	134.2	119.5	107.5	87.3	77.0	68.1	37.3	19.5	0.0	0.0
GPM	2,532	2,532	2,532	2,532	2,532	2,532	2,532	2,532	2,532	0	0
Pounds U3O8	133,271	124,134	110,564	99,409	80,727	71,181	63,031	34,509	18,025	0	0
Period Cost, $/Lb.	$3.46	$3.65	$4.49	$4.43	$5.20	$5.66	$6.28	$21.46	$19.81	NA	NA
Cumulative Cost/Cumulative Production, $/Lb.	$10.85	$10.70	$10.59	$10.50	$10.43	$10.38	$10.34	$10.40	$10.43	$10.45	$10.48

Project Cost Summary												
1 - 8	Labor	$146,676	$146,676	$146,676	$146,676	$142,116	$142,116	$142,116	$142,116	$142,116	$120,312	$104,964
9 - 88, 100	Auxiliary Costs	$20,421	$20,421	$20,421	$20,421	$20,421	$20,421	$20,421	$20,421	$20,421	$15,270	$15,005
90 - 99	Environmental	$1,000	$1,000	$46,900	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$750	$750
101 - 127	Well Completion Costs	$11,680	$11,680	$11,680	$11,680	$11,680	$11,680	$11,680	$380,869	$11,680	$0	$0
190 - 210	Chemicals	$92,818	$88,311	$81,618	$76,116	$66,901	$62,193	$58,173	$44,105	$35,975	$3,000	$3,000
211 - 212	Electrical & Water	$79,815	$79,815	$79,815	$79,815	$79,815	$79,815	$79,815	$79,815	$79,815	$26,908	$26,908
220 - 230	Wellfield Hardware Maintenance	$40,601	$40,601	$40,601	$40,601	$40,601	$40,601	$40,601	$40,601	$40,601	$4,721	$4,721
250 - 260	Plant Hardware Maintenance	$3,205	$3,205	$12,205	$12,205	$12,205	$3,205	$3,205	$3,205	$3,205	$4,325	$4,325
261 - 275	Ancillary Plant Costs	$14,280	$14,280	$14,280	$14,280	$14,280	$14,280	$14,280	$14,280	$14,280	$8,490	$8,490
280 - 288	Yellowcake Drying and Handling	$48,893	$45,541	$40,563	$36,470	$29,616	$26,114	$23,124	$12,660	$8,613	$0	$0
290 - 405	Vehicle Charges	$1,450	$1,450	$1,450	$1,450	$1,450	$1,450	$1,450	$1,450	$1,450	$1,200	$1,200
	Totals	$460,838	$452,979	$496,207	$440,713	$420,084	$402,874	$395,863	$740,521	$357,154	$184,976	$169,363
	Cumulative Totals	$66,531	$66,984	$67,481	$67,921	$68,341	$68,744	$69,140	$69,881	$70,238	$70,423	$70,592
	Plant Capital & Elution/Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Wellfield Replacement Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Plant Operating Expense	$275,095	$267,236	$255,565	$245,970	$229,902	$221,692	$214,681	$190,149	$175,972	$0	$0
	Wellfield Operating Expense	$120,887	$120,887	$120,887	$120,887	$120,887	$120,887	$120,887	$120,887	$120,887	$0	$0
	Restoration & Decommissioning	$64,856	$64,856	$119,756	$73,856	$69,296	$60,296	$60,296	$429,485	$60,296	$184,976	$169,363
	Totals	$460,838	$452,979	$496,207	$440,713	$420,084	$402,874	$395,863	$740,521	$357,154	$184,976	$169,363
	Cumulative Totals	$66,531	$66,984	$67,481	$67,921	$68,341	$68,744	$69,140	$69,881	$70,238	$70,423	$70,592

Total Employment	ERR	ERR	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5
Period	97	98	99	100	101	102	103	104	105	106	107
# Injection Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Extraction Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Monitor Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Definite Wells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# Plugged Holes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
# of Rigs Required	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Wells											
# Injection Wells	0	0	0	0	0	0	0	0	0	0	0
# Extraction Wells	0	0	0	0	0	0	0	0	0	0	0
Production											
PPM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
GPM	0	0	0	0	0	0	0	0	0	0	0
Pounds U3O8	0	0	0	0	0	0	0	0	0	0	0
Period Cost, $/Lb.	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Cumulative Cost/Cumulative Production, $/Lb.	$10.83	$10.85	$10.87	$10.89	$10.90	$10.92	$10.93	$10.94	$10.96	$11.12	$11.18

Project Cost Summary												
1 - 8	Labor	$102,406	$58,000	$58,000	$58,000	$58,000	$58,000	$58,000	$58,000	$58,000	$58,000	$58,000
9 - 88, 100	Auxiliary Costs	$14,961	$14,178	$14,178	$14,178	$14,178	$14,178	$14,178	$14,178	$14,178	$14,178	$14,178
90 - 99	Environmental	$750	$48,450	$750	$750	$750	$750	$750	$750	$750	$1,032,991	$750
101 - 127	Well Completion Costs	$298,867	$0	$0	$0	$0	$0	$0	$0	$0	$0	$326,215
190 - 210	Chemicals	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
211 - 212	Electrical & Water	$26,908	$26,908	$26,908	$26,908	$26,908	$14,128	$1,200	$1,200	$1,200	$1,200	$1,200
220 - 230	Wellfield Hardware Maintenance	$4,721	$4,721	$4,721	$4,721	$4,721	$2,374	($0)	$0	$0	$0	$0
250 - 260	Plant Hardware Maintenance	$4,325	$4,325	$1,075	$1,075	$1,075	$1,075	$1,075	$1,075	$1,075	$1,075	$1,075
261 - 275	Ancillary Plant Costs	$5,490	$5,490	$4,340	$4,340	$4,340	$4,340	$4,340	$4,340	$4,340	$3,290	$3,290
280 - 288	Yellowcake Drying and Handling	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
290 - 405	Vehicle Charges	$1,200	$1,200	$450	$450	$450	$450	$450	$450	$450	$450	$450
	Totals	$462,628	$166,272	$113,422	$113,422	$113,422	$98,295	$82,993	$82,993	$82,993	$1,114,184	$408,158
	Cumulative Totals	$72,952	$73,118	$73,231	$73,345	$73,458	$73,557	$73,640	$73,723	$73,806	$74,920	$75,328
	Plant Capital & Elution/Drying	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Wellfield Replacement Capital	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Plant Operating Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Wellfield Operating Expense	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Restoration & Decommissioning	$462,628	$166,272	$113,422	$113,422	$113,422	$98,295	$82,993	$82,993	$82,993	$1,114,184	$408,158
	Totals	$462,628	$166,272	$113,422	$113,422	$113,422	$98,295	$82,993	$82,993	$82,993	$1,114,184	$408,158
	Cumulative Totals	$72,952	$73,118	$73,231	$73,345	$73,458	$73,557	$73,640	$73,723	$73,806	$74,920	$75,328

Total Employment	19.5	19.5	19.5	19.5	19.5	19.5
Period	108	109	110	111	112	113
# Injection Wells	0.0	0.0	0.0	0.0	0.0	0.0
# Extraction Wells	0.0	0.0	0.0	0.0	0.0	0.0
# Monitor Wells	0.0	0.0	0.0	0.0	0.0	0.0
# Definite Wells	0.0	0.0	0.0	0.0	0.0	0.0
# Plugged Holes	0.0	0.0	0.0	0.0	0.0	0.0
# of Rigs Required	0.0	0.0	0.0	0.0	0.0	0.0
Operating Wells						
# Injection Wells	0	0	0	0	0	0
# Extraction Wells	0	0	0	0	0	0
Production						
PPM	0.0	0.0	0.0	0.0	0.0	0.0
GPM	0	0	0	0	0	0
Pounds U3O8	0	0	0	0	0	0
Period Cost, $/Lb.	NA	NA	NA	NA	NA	NA
Cumulative Cost/Cumulative Production, $/Lb.	$11.21	$11.23	$11.25	$11.28	$11.29	$11.36

Project Cost Summary							
1 - 8	Labor	$58,000	$58,000	$58,000	$58,000	$58,000	$58,000
9 - 88, 100	Auxiliary Costs	$14,178	$14,178	$14,178	$14,178	$14,178	$14,178
90 - 99	Environmental	$75,750	$75,750	$75,750	$75,750	$750	$750
101 - 127	Well Completion Costs	$0	$0	$0	$0	$0	$388,723
190 - 210	Chemicals	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
211 - 212	Electrical & Water	$1,200	$1,200	$1,200	$1,200	$1,200	$1,200
220 - 230	Wellfield Hardware Maintenance	$0	$0	$0	$0	$0	$0
250 - 260	Plant Hardware Maintenance	$1,075	$1,075	$1,075	$1,075	$1,075	$1,075
261 - 275	Ancillary Plant Costs	$3,290	$3,290	$3,290	$3,290	$3,290	$3,290
280 - 286	Yellowcake Drying and Handling	$0	$0	$0	$0	$0	$0
290 - 405	Vehicle Charges	$450	$450	$450	$450	$450	$450
	Totals	$156,943	$156,943	$156,943	$156,943	$81,943	$470,666
	Cumulative Totals	$75,485	$75,642	$75,799	$75,956	$76,038	$76,508
	Plant Capital & Elution/Drying	$0	$0	$0	$0	$0	$0
	Wellfield Replacement Capital	$0	$0	$0	$0	$0	$0
	Plant Operating Expense	$0	$0	$0	$0	$0	$0
	Wellfield Operating Expense	$0	$0	$0	$0	$0	$0
	Restoration & Decommissioning	$156,943	$156,943	$156,943	$156,943	$81,943	$470,666
	Totals	$156,943	$156,943	$156,943	$156,943	$81,943	$470,666
	Cumulative Totals	$75,485	$75,642	$75,799	$75,956	$76,038	$76,508

99