CAMECO RESOURCES
CROW BUTTE OPERATION

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February 25, 2009

Mr. Michael Linder
Director
Nebraska Department of Environmental Quality
PO Box 98922
Lincoln, Nebraska 68509-8922

Subject: Revised 2009 Surety Estimate
Class III Underground Injection Control Permit Number NE 0122611
Class I Underground Injection Control Permit Number NE 0210457

Dear Mr. Linder:

Attached is a revision to the 2009 Surety Estimate submitted on September 29, 2008 for the Crow Butte Uranium Mine. This revised estimate addresses issues raised by the Department in a letter received November 25, 2008, which asked for further clarification on the number of pore volumes used in restoration. Also attached as required in the approved minor permit modification dated August 21, 2007, is an audit statement from George W. Klein, an independent professional auditing firm.

This revised surety estimate for 2009 is $27,871,170, a decrease of $6,336,744 over the 2009 surety estimate submitted on September 29, 2008. The change is an increase of $2,663,498 over the approved 2008 surety estimate. The following is a summary of the changes:

1) **Ground Water Restoration**

Sheet 3 - The titles of *Groundwater Sweep* were changed to *IX Treatment* to provide a more accurate description of the process. Based on the WorleyParsons report, *Wellfield Restoration Modeling Crow Butte Resources Mine Units 2-5* (attached), the pore volume for IX Treatment was estimated to be 3 pore volumes. The pore volumes for recirculation were increased from 1 to 2. Also attached is a schedule that shows the timeline for restoring each mine unit.

Sheet 4 – The title *Groundwater Sweep* was changed to *IX Treatment* and the months for stabilization were increased from 6 to 12.

Sheet 6 – Under *Supervisory Labor Costs* an additional line was added, at the auditor's request, to make it easier for the reader to see the cost savings associated with concurrent restoration of

multiple mine units.

2) **Evaporation Pond Reclamation**
Sheet 15 – The estimated *1991 to 2009 Total Production (gallons)* was increased from 26,508,584 to 26,516,468,400 gallons. (The original submittal did not include the 2009 production).

3) **Groundwater IX Treatment (GIX) Unit Costs**
Sheet 25 – This page was changed from *Groundwater Sweep* to *Groundwater IX Treatment* to describe the actual treatment process that is being used.

4) **Groundwater Reverse Osmosis (RO) Treatment Unit Costs**
Sheet 26 – The *RO Unit Pump* horsepower was changed from 405 hp to 170 hp. In the original submittal it was incorrectly estimated that 66 pumps would be used to produce 600 gpm of flow through the RO when it only requires 19 pumps to produce this flow. This results in a reduction of 235 horsepower. A *Membrane Replacement Costs per 1000 Gallons* line has been added to account for the costs associated with replacing the membranes in the RO units. The *Reverse Osmosis Production Rate* was changed from 400 to 600 GPM. These changes lowered the *Total RO Costs per 1000 Gallons* from $2.26 to $1.94.

5) **Groundwater Recirculation Unit Costs**
Sheet 27 – The chemical costs for adding reductant was removed from this unit. Reductant is not used during the recirculation process. This changes the *Total Recirculation Cost per 1000 Gallons* from $0.93 to $0.72.

6) **Well Abandonment Unit Costs**
Sheet 28 – Under *Well Abandonment Costs*, a new line was added to account for the labor costs associated with abandoning a well. This raised the *Total Estimated Cost per Foot* from $0.71 to $0.74.

7) **Master Cost Basis**
Sheet 29 – The *Wellfield Area (ft2)* for Mine Unit 10 was changed from 4,878,720 to 3,610,000 ft2 and Mine Unit 11 was changed from 3,049,200 to 2,100,000 ft2. It was found that an error had been made when calculating the areas in the prior submittal. The *Avg. Completed Thickness* for Mine 10 was changed from 20 to 18 ft and Mine Unit 11 was changed from 25 to 22 ft. The completion thickness is based on the current drilling data and is the thickness that was used for these two mine units in the 2008 surety estimate.

The revised estimate continues to include the development and initial mining of Mine Unit 11, with four wellhouses installed in this mine unit by the end of 2009. 441 wells are also projected for Mine

Unit 11, which is an increase of 75 wells over the 2008 surety estimate. In addition, 30 additional wells are included for Mine Unit 10. In all, the 2009 surety includes the costs associated with 105 new wells installed in Mine Units 10 and 11. The areal extent of Mine Unit 10 was increased by 374,120 square feet (8.6 acres) and Mine Unit 11 was reduced by 223,200 square feet (5.1 acres) to reflect the projected expansion in these mine units. The revision still includes expansion of the Restoration Building to allow for the addition of two IX columns and associated piping and the installation of an additional deep disposal well.

The most significant factors contributing to the decrease in the revised surety estimate include groundwater restoration (-$5,141,316), contract administration (-$506,939), and contingency (-$760,410). Sheet 2 of the attached estimate presents the changes for selected cost elements over the 2008 surety estimate.

Upon approval of the surety estimate by the NDEQ, the Crow Butte Operation (CBO) will provide a secured letter of credit to the State of Nebraska in an amount equal to the updated surety estimate.

If you have any questions or require any further information, please do not hesitate to call me at (308) 665-2215 ext 114.

Sincerely,
CAMECO RESOURCES
CROW BUTTE OPERATION

Larry Teahon

Larry Teahon
Manager Health, Safety and Environmental Affairs

Enclosure
cc: Mr. Keith I. McConnell, Deputy Director
Decommissioning and Uranium Recovery Licensing Directorate
Division of Waste Management and Environmental Protection
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Steven P. Collings, Denver Office
Scott Bakken, Denver Office
Jim Stokey, Crow Butte Resources
CBR File

REVIEW OF
CROW BUTTE RESOURCES, INC.

URANIUM PROJECT 2009 SURETY ESTIMATE
REVISED FEBRUARY 2009
AGREED UPON PROCEDURES ENGAGEMENT REVIEW

George W. Klein
Certified Public Accountant
Chadron, Nebraska

GEORGE W. KLEIN
CERTIFIED PUBLIC ACCOUNTANT

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February 5, 2009

Stephen P. Collings, President
Crow Butte Resources, Inc.
141 Union Boulevard, Suite 320
Lakewood, CO 80228

Dear Mr. Collings:

This report shows the findings for each of the services I have performed as outlined in our engagement letter for the Crow Butte Uranium Project 2009 Surety Estimate. These findings were based on my review of the Crow Butte Uranium Project 2009 Surety Estimate, Revised February 2009, spreadsheets received January 20, 2009 through February 5, 2009 with the Total 2009 Surety Bond estimate totaling $27,871,170.

> No findings in the review of the results of the mathematical calculations used in the surety estimate worksheet. A few cosmetic items were discussed but they did not affect the total calculation of the surety amount.
>
> No findings in the review and confirmation of selected items that support the master costs used in preparing the surety estimate worksheet.
>
> No findings in the further tests and procedures I considered necessary to enable me to express an opinion on the master costs and the calculations used in the surety estimate.

This agreed upon procedures review was conducted in accordance with Statements on Standards for Accounting and Review Services issued by the American Institute of Certified Public Accountants. I was not engaged to and did not conduct an audit on Crow Butte Resources Financial Statements , and accordingly, will not express an opinion or any other form of assurance involved in conducting an audit of their financial statements.

The management of Crow Butte Resources, Inc. was responsible for making all records and related information used in the preparation of the surety estimate available to me. They were responsible for the accuracy and completeness of that information and for disclosing all significant information that might affect the surety estimate.

This report is intended solely for the information and use of the Crow Butte Resources, Inc., the Nebraska Department of Environmental Quality, and Fuel Cycle Licensing Branch in evaluating the Crow Butte Uranium Project 2009 Surety Estimate, Revised February 2009 and is not intended and should not be used by anyone other than these specified parties.

I appreciate the opportunity to be of service to the Crow Butte Resources, Inc.

Sincerely,

George W. Klein, CPA

GWK/jg

CROW BUTTE RESOURCES, INC.
URANIUM PROJECT 2009 SURETY ESTIMATE
REVISED FEBRUARY 5, 2009
AGREED UPON PROCEDURES ENGAGEMENT REVIEW
Prepared 2/5/09 jg

I received the first spreadsheet for the Crow Butte Uranium Project 2009 Surety Estimate, Revised February 2009 on January 20, 2009. It was then revised on February 5, 2009 to make the suggested format changes and corrections listed below.

The following is a summary of the tests performed and items reviewed:

I. Traced formula references to cells used throughout spreadsheet to assure the information being used was being pulled correctly. Printed out all the formulas and cell locations so they could be easily reviewed and then manually calculated formulas. Selected formulas from each spreadsheet tab and followed them to the end of the column's calculations. The following are minor and cosmetic items encountered that were all discussed with Larry Teahon, Manager, Environmental Health and Safety, on January 28, 2009.

1) The header on all of the worksheet tabs needs to be updated to reflect that it is being revised in January 2009. This was then changed to February 2009 with the second spreadsheet received on February 5, 2009.

2) On the Ground Water Restoration tab I suggested inserting a line with the description explaining the reduction being taken for ½ of the labor costs for mines four through eleven. This will aid the reader in understanding how the subtotal supervisory labor per mine unit is calculated and also resolves a rounding issue. Without this change it was unclear as to how the numbers were being added up as the formulas were reducing it by one half. The total formulas would then need to be changed so that they are simply the sum of the fields involved including the new reduction line.

3) Also suggested that the footer on the renamed Groundwater Sweep tab be updated to agree with the new title of Groundwater IX Treatment.

II. Confirmed that the previously confirmed rental, landfill, Consumer Price Index, and diesel prices remained the same on this revision.

Crow Butte Resources, Inc.
Crow Butte Uranium Project 2009 Surety Estimate
(Revised February 2009)

Total Restoration and Reclamation Cost Estimate

I.	Groundwater Restoration (Sheets 3 to 6)		$14,168,117
II.	Wellfield Reclamation (Sheets 7 to 10)		$6,280,247
III.	Commercial Plant Reclamation/Decommissioning (Sheets 11 to 14)		$661,213
IV.	R.O. Building Reclamation/Decommissioning (Sheets 11 to 14)		$133,719
V.	Evaporation Pond Reclamation (Sheets 15 to 18)		$730,184
VI.	Miscellaneous Site Reclamation (Sheets 19 to 21)		$151,651
VII.	Deep Disposal Well Reclamation (Sheet 22)		$143,514
VIII.	I-196 Brule Aquifer Restoration (Sheets 23 to 24)		$28,291
	Subtotal Reclamation and Restoration Cost Estimate		$22,296,936
	Contract Administration	10%	$2,229,694
	Contingency	15%	$3,344,540
		TOTAL	$27,871,170

Crow Butte Resources, Inc.
Crow Butte Uranium Project 2009 Surety estimate
(Revised February 2009)

Comparison of Total Surety and Major Cost Elements to Previous Year			
Projected Costs for 2009 are Compared with Costs for 2008 and Changes are Calculated			
Total Surety	**2009**	**2008**	**Change**
	$27,871,170	$25,207,672	$2,663,498
Contract Administration	**2009**	**2008**	**Change**
	$2,229,694	$2,016,614	$213,080
	2009	**2008**	**Change**
Contingency	$3,344,540	$3,024,921	$319,619
Groundwater Restoration	**2009**	**2008**	**Change**
Groundwater Sweep			
Total Gallons Processed (Kgal)	1,869,198	522,280	1,346,918
Total Cost	$1,289,747	$339,482	$950,265
RO Treatment			
Total Gallons Processed (Kgal)	3,738,396	3,133,680	604,716
Total Cost	$7,252,488	$6,612,065	$640,423
Recirculation			
Total Gallons Processed (Kgal)	1,246,132	522,280	723,852
Total Cost	$897,215	$459,606	$437,609
Sampling and Monitoring			
Total On Site Samples	38,334	31,118	7,216
Total On Site Analysis Costs	$2,032,852	$1,597,909	$434,943
Total Contract Samples	1,875	1,355	520
Total Contract Analysis Costs	$375,000	$271,000	$104,000
Wellfield Reclamation	**2009**	**2008**	**Change**
Pipeline Removal and Loading	$949,681	$897,940	$51,741
Well Abandonment			
Total Number of Wells	4,503	4,402	101
Total Abandonment Cost	$2,150,843	$1,955,260	$195,583
Site Reclamation	**2009**	**2008**	**Change**
Site Earthwork	$607,616	$577,559	$30,057
Plant and Equipment Decontamination	**2009**	**2008**	**Change**
Decontamination Costs	$116,345	$113,016	$3,329
Demolition Costs	$355,259	$346,500	$8,759
Piping Shredding Costs	$336,955	$316,023	$20,932
Transportation and Disposal	**2009**	**2008**	**Change**
Byproduct Material			
Soil-Type Materials, Total Volume (Yd3)	4,306	4,265	41
Soil-Type Materials, Total Cost	$593,616	$588,071	$5,545
Unpackaged Bulk Materials, Total Volume (Yd3)	2,388	2,293	95
Unpackaged Bulk Materials, Total Cost	$800,775	$768,862	$31,913

Crow Butte Resources Inc.
Crow Butte Uranium Project 2009 Surety Estimate
(Revised February 2009)

Ground Water Restoration

				Mine Unit 2	Mine Unit 3	Mine Unit 4	Mine Unit 5	Mine Unit 6	Mine Unit 7	Mine Unit 8	Mine Unit 9	Mine Unit 10	Mine Unit 11	Total
I.	**IX Treatment Costs**													
	PV's Required			3	3	3	3	3	3	3	3	3	3	
	Total Kgals for Treatment			54054	47682	86751	131400	151092	177873	269256	227574	422865	300651	1869198
	IX Treatment Unit Cost ($/Kgal)	(Sheet 25)		$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	$0.69	
	Subtotal IX Treatment Costs per Wellfield			**$37,297.26**	**$32,900.58**	**$59,858.19**	**$90,666.00**	**$104,253.48**	**$122,732.37**	**$185,786.64**	**$157,026.06**	**$291,776.85**	**$207,449.19**	**$1,289,746.62**
Total IX Treatment Costs				**$1,289,746.62**										
II.	**Reverse Osmosis Costs**													
	PV's Required			6	6	6	6	6	6	6	6	6	6	
	Total Kgals for Treatment			108108	95364	173502	262800	302184	355746	538512	455148	845730	601302	3738396
	Reverse Osmosis Unit Cost ($/Kgal)	(Sheet 26)		$1.94	$1.94	$1.94	$1.94	$1.94	$1.94	$1.94	$1.94	$1.94	$1.94	$1.94
	Subtotal Reverse Osmosis Costs per Wellfield			**$209,729.52**	**$185,006.16**	**$336,593.88**	**$509,832.00**	**$586,236.96**	**$690,147.24**	**$1,044,713.28**	**$882,987.12**	**$1,640,716.20**	**$1,166,525.88**	**$7,252,488.24**
Total Reverse Osmosis Costs				**$7,252,488.24**										
III.	**Recirculation Costs**													
	PV's Required			2	2	2	2	2	2	2	2	2	2	
	Total Kgals for Treatment			36036	31788	57834	87600	100728	118582	179504	151716	281910	200434	1246132
	Recirculation Unit Cost ($/Kgal)	(Sheet 27)		$0.72	$0.72	$0.72	$0.72	$0.72	$0.72	$0.72	$0.72	$0.72	$0.72	$0.72
	Subtotal Recirculation Costs per Wellfield			**$25,945.92**	**$22,887.36**	**$41,640.48**	**$63,072.00**	**$72,524.16**	**$85,379.04**	**$129,242.88**	**$109,235.52**	**$202,975.20**	**$144,312.48**	**$897,215.04**
Total Recirculation Costs				**$897,215.04**										
IV.	**Consumables**													
	Spare parts, filters and consumables =	$20,475.00	year											
	Active restoration period (months)			5.90	5.21	9.47	14.35	16.50	19.42	29.40	24.85	46.18	32.83	204.11
	Consumable usage (months restoration x annual rate estimate)			$10,066.88	$8,889.56	$16,158.19	$24,484.69	$28,153.13	$33,135.38	$50,163.75	$42,400.31	$78,794.63	$56,016.19	$348,262.71
	Subtotal Consumables per Mine Unit			**$10,066.88**	**$8,889.56**	**$16,158.19**	**$24,484.69**	**$28,153.13**	**$33,135.38**	**$50,163.75**	**$42,400.31**	**$78,794.63**	**$56,016.19**	**$348,262.71**
Total Consumables Costs				**$348,262.71**										

Crow Butte Resources Inc.
Crow Butte Uranium Project 2009 Surety Estimate
(Revised February 2009)

Ground Water Restoration

				Mine Unit 2	Mine Unit 3	Mine Unit 4	Mine Unit 5	Mine Unit 6	Mine Unit 7	Mine Unit 8	Mine Unit 9	Mine Unit 10	Mine Unit 11	Total
V.	**Monitoring and Sampling Costs**													
	Guideline 8 analysis =	$200.00	analysis											
	6 parameter in-house analysis =	$53.03	analysis											
	Total restoration wells			12	18	43	33	29	25	30	21	32	24	267
	Total monitor wells			13	10	20	48	54	33	50	33	63	45	369
	IX Treatment duration (months)			1.07	0.95	1.72	2.61	3.00	3.53	5.35	4.52	8.40	5.97	37.12
	Reverse Osmosis duration (months)			4.11	3.63	6.60	10.00	11.50	13.54	20.49	17.32	32.18	22.88	142.25
	Recirculation duration (months)			0.72	0.63	1.15	1.74	2.00	2.35	3.56	3.01	5.60	3.98	24.74
	Stabilization duration (months)			12	12	12	12	12	12	12	12	12	12	
A.	Restoration Well Sampling													
1.	Well Sampling prior to restoration start													
	# of Wells			12	18	43	33	29	25	30	21	32	24	267
	$/sample			$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	
2.	IX Treatment Sampling													
	# of Wells			12	18	43	33	29	25	30	21	32	24	
	Total # samples			24	18	86	99	87	100	180	105	288	144	1131
	$/sample			$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	
3.	RO Sampling													
	# of Wells			12	18	43	33	29	25	30	21	32	24	
	Total # samples			48	72	301	330	348	350	600	357	1024	552	3982
	$/sample			$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	

Crow Butte Resources Inc.
Crow Butte Uranium Project 2009 Surety Estimate
(Revised February 2009)

Ground Water Restoration												
	Mine Unit 2	**Mine Unit 3**	**Mine Unit 4**	**Mine Unit 5**	**Mine Unit 6**	**Mine Unit 7**	**Mine Unit 8**	**Mine Unit 9**	**Mine Unit 10**	**Mine Unit 11**	**Total**
4. Recirculation Sampling											
# of Wells	12	18	43	33	29	25	30	21	32	24	
Total # samples	12	18	86	66	58	75	120	84	192	96	807
$/sample	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	
5. Stabilization Sampling (Guideline 8)											
# of Wells	12	18	43	33	29	25	30	21	32	24	
Total # samples	36	54	129	99	87	75	90	63	96	72	801
$/sample	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	$200.00	
6. Stabilization Sampling (6 parameter in-house)											
# of Wells	12	18	43	33	29	25	30	21	32	24	
Total # samples	144	216	516	396	348	300	360	252	384	288	3204
$/sample	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	
7. Monitor Well Sampling											
# of Wells	13	10	20	48	54	33	50	33	63	45	
$/sample	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	$53.03	
Total # samples (2.2/mo for entire period)	512	379	945	2783	3386	2281	4554	2675	8064	4438	30017
8. Other Laboratory Costs											
Radon, urinalysis, etc. = $971.25 month											
Total for Other Laboratory Costs:	$5,730.38	$5,060.21	$9,197.74	$13,937.44	$16,025.63	$18,861.68	$28,554.75	$24,135.56	$44,852.33	$31,886.14	$198,241.86
Subtotal Monitoring and Sampling Costs per Mine Unit	**$56,336.22**	**$59,385.76**	**$158,797.18**	**$244,869.68**	**$271,907.70**	**$214,595.61**	**$378,507.57**	**$237,454.23**	**$626,425.13**	**$357,814.80**	**$2,606,093.88**
Total Monitoring and Sampling Costs	**$2,606,093.88**										

Crow Butte Resources Inc.
Crow Butte Uranium Project 2009 Surety Estimate
(Revised February 2009)

Ground Water Restoration

				Mine Unit 2	Mine Unit 3	Mine Unit 4	Mine Unit 5	Mine Unit 6	Mine Unit 7	Mine Unit 8	Mine Unit 9	Mine Unit 10	Mine Unit 11	Total
VI.	**Supervisory Labor Cost**													
	Engineer Support =	$9,381.65	month											
	HP Technician support =	$4,743.90	month											
	Active restoration period (months)			5.90	5.21	9.47	14.35	16.50	19.42	29.40	24.85	46.18	32.83	
	Stabilization period (months)			12	12	12	12	12	12	12	12	12	12	
	1 Engineer support during active restoration			$55,351.74	$48,878.40	$88,844.23	$134,626.68	$154,797.23	$182,191.64	$275,820.51	$233,134.00	$433,244.60	$307,999.57	$1,914,888.60
	2 HP Technician support during active restoration			$27,989.01	$24,715.72	$44,924.73	$68,074.97	$78,274.35	$92,126.54	$139,470.66	$117,885.92	$219,073.30	$155,742.24	$968,277.44
	3 Engineer support during final stabilization										$112,579.80	$112,579.80	$112,579.80	$337,739.40
	4 HP Technician support during final stabilization										$56,926.80	$56,926.80	$56,926.80	$170,780.40
	5 Cost reduction due to concurrent restoration of Mine Units					-$66,884.48	-$101,350.83	-$116,535.79	-$137,159.09	-$207,645.58	-$260,263.26	-$410,912.25	-$316,624.50	-$1,617,375.77
	Subtotal Supervisory Labor per Mine Unit			**$83,340.75**	**$73,594.12**	**$66,884.48**	**$101,350.83**	**$116,535.79**	**$137,159.09**	**$207,645.59**	**$260,263.26**	**$410,912.25**	**$316,623.91**	**$1,774,310.07**
Total Supervisory Labor Costs				**$1,774,310.07**										
TOTAL RESTORATION COST PER WELLFIELD				**$422,716.55**	**$382,663.54**	**$679,932.40**	**$1,034,275.20**	**$1,179,611.22**	**$1,283,148.73**	**$1,996,059.71**	**$1,689,366.50**	**$3,251,600.26**	**$2,248,742.45**	**$14,168,116.56**
TOTAL GROUND WATER RESTORATION COSTS				**$14,168,116.56**										

Crow Butte Resources Inc.
Crow Butte Uranium Project 2009 Surety Estimate
(Revised February 2009)

Wellfield Reclamation

	Mine Unit 1	Mine Unit 2	Mine Unit 3	Mine Unit 4	Mine Unit 5	Mine Unit 6	Mine Unit 7	Mine Unit 8	Mine Unit 9	Mine Unit 10	Mine Unit 11	Totals
Wellfield Piping												
Assumptions:												
Number of Wellhouses	0	3	3	5	7	7	6	8	7	8	4	58
Total Mine Unit surface area (acres)	9.27	11.70	13.46	23.72	31.75	34.61	51.01	57.92	48.95	82.87	48.21	413.47
Total length of small diameter production and injection lines (laterals) (ft)	0	34000	39520	68900	106080	128700	160500	187000	161950	96800	69000	1052450
Total length of 3/8-inch hose (ft)					66300							66300
Total length 1-1/4-inch stinger pipe (ft)	0	0	0	1600	0	89100	89400	115500	96600	75000	45000	512200
Total length of 2-inch downhole production pipe (ft)	900	8000	8000	12000	14000	70800	71200	94000	76400	60000	36000	450900
Total Length of Trunkline (6-inch) (ft)	1000	1600	4000					900				7500
Total Length of Trunkline (8-inch) (ft)	4400	1300	1450	7800	3700	2000	1000	2100	2225	3200	1400	30575
Total Length of Trunkline (10-inch) (ft)								400				400
Total Length of Trunkline (12-inch) (ft)				2900	6500	18900	10000	5000	16900	11525	5450	3000	82175
Total Length of All Trunkline (ft)	5400	2900	8350	14300	22600	12000	6000	20300	13750	8650	6400	120650
Total number of production wells	3	52	57	96	187	187	205	248	195	280	140	1650
Total number of injection wells	0	79	96	169	221	309	370	412	324	440	256	2676
Total number of shallow monitor wells	0	3	3	11	25	28	25	30	20	32	26	203
Total number of perimeter monitor wells	11	10	7	9	23	26	8	20	13	31	19	177
I. Production and Injection Piping												
A. Removal and Loading												
Production and Injection Piping Removal Unit Cost ($/ft of pipe)	$0.68	$0.68	$0.68	$0.68	$0.68	$0.68	$0.68	$0.68	$0.68	$0.68	$0.68	
Subtotal Production and Injection Piping Removal and Loading Costs	*$0.00*	*$23,120.00*	*$26,873.60*	*$46,852.00*	*$72,134.40*	*$87,516.00*	*$109,140.00*	*$127,160.00*	*$110,126.00*	*$65,824.00*	*$46,920.00*	*$715,666.00*
B. Pipe Shredding												
Production and Injection Piping Shredding Unit Cost ($/ft of pipe)	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	
Subtotal Production and Injection Piping Removal and Loading Costs	*$0.00*	*$2,720.00*	*$3,161.60*	*$5,512.00*	*$8,486.40*	*$10,296.00*	*$12,840.00*	*$14,960.00*	*$12,956.00*	*$7,744.00*	*$5,520.00*	*$84,196.00*
C. Equipment Costs												
Cat 924G Loader Unit Costs for removal (450'/day)	$0.00	$36,302.93	$42,196.82	$73,566.83	$113,265.15	$137,417.28	$171,371.20	$199,666.13	$172,919.41	$103,356.59	$73,673.60	
Shredder Unit Costs for shredding (450'/day)	$0.00	$7,253.33	$8,430.93	$14,698.67	$22,630.40	$27,456.00	$34,240.00	$39,893.33	$34,549.33	$20,650.67	$14,720.00	
Subtotal Equipment Costs	*$0.00*	*$43,556.26*	*$50,627.75*	*$88,265.50*	*$135,895.55*	*$164,873.28*	*$205,611.20*	*$239,559.46*	*$207,468.74*	*$124,007.26*	*$88,393.60*	*$1,348,258.60*
D. Transport and Disposal Costs (NRC-Licensed Facility)												
Chipped Volume Reduction (ft^3/ft)	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	0.0069	
Chipped Volume per Wellfield (yd^3)	0.0	8.7	10.1	17.6	27.1	32.9	41.0	47.8	41.4	24.7	17.6	
Volume for Disposal Assuming 25% Void Space (yd^3)	0.0	10.9	12.6	22.0	33.9	41.1	51.3	59.8	51.8	30.9	22.0	336.3
Transportation and Disposal Unit Cost ($/$yd^3$) Unpackaged Bulk	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	
Subtotal Production and Injection Piping Transport and Disposal Costs	*$0.00*	*$3,650.08*	*$4,219.36*	*$7,367.14*	*$11,352.09*	*$13,763.16*	*$17,178.83*	*$20,025.23*	*$17,346.27*	*$10,347.48*	*$7,367.14*	*$112,616.78*
Total Production and Injection Piping Costs	**$0.00**	**$73,046.34**	**$84,882.31**	**$147,996.64**	**$227,868.44**	**$276,448.44**	**$344,770.03**	**$401,704.69**	**$347,897.01**	**$207,922.74**	**$148,200.74**	**$2,260,737.38**

Crow Butte Resources Inc.
Crow Butte Uranium Project 2009 Surety Estimate
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Wellfield Reclamation

	Mine Unit 1	Mine Unit 2	Mine Unit 3	Mine Unit 4	Mine Unit 5	Mine Unit 6	Mine Unit 7	Mine Unit 8	Mine Unit 9	Mine Unit 10	Mine Unit 11	Totals
II. Trunklines												
A. Removal and Loading												
Trunkline Removal Unit Cost ($/ft of pipe)	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	
Subtotal Trunkline Removal and Loading Costs	*$8,262.00*	*$4,437.00*	*$12,775.50*	*$21,879.00*	*$34,578.00*	*$18,360.00*	*$9,180.00*	*$31,059.00*	*$21,037.50*	*$13,234.50*	*$9,792.00*	*$184,594.50*
B. Pipe Shredding												
Trunkline Shredding Unit Cost ($/ft of pipe)	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	$1.53	
Subtotal Trunkline Shredding Costs	*$8,262.00*	*$4,437.00*	*$12,775.50*	*$21,879.00*	*$34,578.00*	*$18,360.00*	*$9,180.00*	*$31,059.00*	*$21,037.50*	*$13,234.50*	*$9,792.00*	*$184,594.50*
C. Equipment Costs												
Cat 924G Loader Unit Costs for removal (200'/day)	$12,972.96	$6,966.96	$20,060.04	$34,354.32	$54,294.24	$28,828.80	$14,414.40	$48,768.72	$33,033.00	$20,780.76	$15,375.36	
Shredder Unit Costs for shredding (200'/day)	$2,592.00	$1,392.00	$4,008.00	$6,864.00	$10,848.00	$5,760.00	$2,880.00	$9,744.00	$6,600.00	$4,152.00	$3,072.00	
Subtotal Equipment Costs	*$15,564.96*	*$8,358.96*	*$24,068.04*	*$41,218.32*	*$65,142.24*	*$34,588.80*	*$17,294.40*	*$58,512.72*	*$39,633.00*	*$24,932.76*	*$18,447.36*	*$347,761.56*
D. Transport and Disposal Costs (NRC-Licensed Facility)												
Chipped Volume Reduction (6-inch) (ft^3/ft)	0.0651	0.0651	0.0651	0.0651	0.0651	0.0651	0.0651	0.0651	0.0651	0.0651	0.0651	
Chipped Volume Reduction (8-inch) (ft^3/ft)	0.1103	0.1103	0.1103	0.1103	0.1103	0.1103	0.1103	0.1103	0.1103	0.1103	0.1103	
Chipped Volume Reduction (10-inch) (ft^3/ft)	0.1712	0.1712	0.1712	0.1712	0.1712	0.1712	0.1712	0.1712	0.1712	0.1712	0.1712	
Chipped Volume Reduction (12-inch) (ft^3/ft)	0.2408	0.2408	0.2408	0.2408	0.2408	0.2408	0.2408	0.2408	0.2408	0.2408	0.2408	
Chipped Volume per Wellfield (yd^3)	20.4	9.2	41.4	89.8	183.7	97.4	48.7	164.0	111.9	61.7	50.3	
Volume for Disposal Assuming 25% Void Space (ft^3)	25.5	11.5	51.8	112.3	229.6	121.8	60.9	205.0	139.9	77.1	62.9	1098.3
Transportation and Disposal Unit Cost ($/$ft^3$)	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	
Subtotal Transport and Disposal Costs	*$8,539.19*	*$3,851.01*	*$17,346.27*	*$37,605.90*	*$76,886.15*	*$40,787.17*	*$20,393.58*	*$68,648.35*	*$46,848.31*	*$25,818.48*	*$21,063.32*	*$367,787.73*
Total Trunkline Costs	**$40,628.15**	**$21,083.97**	**$66,965.31**	**$122,582.22**	**$211,184.39**	**$112,095.97**	**$56,047.98**	**$189,279.07**	**$128,556.31**	**$77,220.24**	**$59,094.68**	**$1,084,738.29**
III. Downhole Pipe												
A. Removal and Loading												
Downhole Piping Removal Unit Cost ($/ft of pipe)	$0.080	$0.080	$0.080	$0.080	$0.080	$0.080	$0.080	$0.080	$0.080	$0.080	$0.080	
Downhole Hosing Removal Unit Cost ($/ft of pipe)	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	$0.150	
Removal of 1-1/4-inch stinger pipe	$0.00	$0.00	$0.00	$128.00	$0.00	$7,128.00	$7,152.00	$9,240.00	$7,728.00	$6,000.00	$3,600.00	
Removal of downhole production pipe	$72.00	$640.00	$640.00	$960.00	$1,120.00	$5,632.00	$5,696.00	$7,520.00	$6,112.00	$4,800.00	$2,880.00	
Removal of downhole hose	$0.00	$0.00	$0.00	$0.00	$9,945.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Subtotal Downhole Piping Removal and Loading Costs	*$72.00*	*$640.00*	*$640.00*	*$1,088.00*	*$11,065.00*	*$12,760.00*	*$12,848.00*	*$16,760.00*	*$13,840.00*	*$10,800.00*	*$6,480.00*	*$86,993.00*
B. Pipe Shredding												
Downhole Piping Shredding Unit Cost ($/ft of pipe)	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	$0.070	
Subtotal Downhole Piping Shredding Costs	*$63.00*	*$560.00*	*$560.00*	*$952.00*	*$980.00*	*$11,165.00*	*$11,242.00*	*$14,665.00*	*$12,110.00*	*$9,450.00*	*$5,670.00*	*$67,417.00*
C. Equipment Costs												
Smeal Unit Costs for removal	$45.00	$400.00	$400.00	$680.00	$700.00	$7,975.00	$8,030.00	$10,475.00	$8,650.00	$6,750.00	$4,050.00	
Shredder Unit Costs for shredding	$19.20	$170.67	$170.67	$290.13	$298.67	$3,402.67	$3,426.13	$4,469.33	$3,690.67	$2,880.00	$1,728.00	
Subtotal Equipment Costs	*$64.20*	*$570.67*	*$570.67*	*$970.13*	*$998.67*	*$11,377.67*	*$11,456.13*	*$14,944.33*	*$12,340.67*	*$9,630.00*	*$5,778.00*	*$68,701.14*

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Wellfield Reclamation

	Mine Unit 1	Mine Unit 2	Mine Unit 3	Mine Unit 4	Mine Unit 5	Mine Unit 6	Mine Unit 7	Mine Unit 8	Mine Unit 9	Mine Unit 10	Mine Unit 11	Totals
D. Transport and Disposal Costs (NRC-Licensed Facility)												
Chipped Volume Reduction - 1-1/4-inch stinger (ft^3/ft)	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	
Chipped Volume Reduction - 2-inch downhole production (ft^3/ft)	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	0.0074	
Volume Reduction - 3/8-inch hose (ft3/ft)	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	0.0313	
Chipped Volume - 1-1/4-inch stinger (ft^3)	0	0	0	7	0	392	393	508	425	330	198	
Chipped Volume - 2-inch downhole production (ft^3)	7	59	59	89	104	521	527	696	565	444	266	
Volume 3/8-inch hose (ft3)	0	0	0	0	2075	0	0	0	0	0	0	
Volume for Disposal Assuming 25% Void Space (yd^3)	0.3	2.7	2.7	4.4	100.9	42.3	42.6	55.7	45.8	35.8	21.5	354.7
Transportation and Disposal Unit Cost ($/$yd^3$) (Unpackaged Bulk)	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	$334.87	
Subtotal Downhole Piping Transport and Disposal Costs	*$100.46*	*$904.15*	*$904.15*	*$1,473.43*	*$33,788.38*	*$14,165.00*	*$14,265.46*	*$18,652.26*	*$15,337.05*	*$11,988.35*	*$7,199.71*	*$118,778.40*
Total Downhole Piping Costs	**$299.66**	**$2,674.82**	**$2,674.82**	**$4,483.56**	**$46,832.05**	**$49,467.67**	**$49,811.59**	**$65,021.59**	**$53,627.72**	**$41,868.35**	**$25,127.71**	**$341,890**
IV. Surface Reclamation												
A. Removal and disposal of contaminated soil around wells												
Volume of contaminated soil (0.37 yd3 per injection and production well)	1.11	48.47	56.61	98.05	150.96	183.52	212.75	244.20	192.03	266.40	146.52	1600.62
Disposal of contaminated soil $137.87 per yd3	$153.04	$6,682.56	$7,804.82	$13,518.15	$20,812.86	$25,301.90	$29,331.84	$33,667.85	$26,475.18	$36,728.57	$20,200.71	$220,677.48
Equipment (Cat 924G loader at 2 yd3/hr)	$33.33	$1,455.55	$1,700.00	$2,944.44	$4,533.33	$5,511.11	$6,388.88	$7,333.33	$5,766.66	$7,999.99	$4,400.00	
Labor (1 man-hour per 2 Yd3)	$10.62	$463.86	$541.76	$938.34	$1,444.69	$1,756.29	$2,036.02	$2,336.99	$1,837.73	$2,549.45	$1,402.20	
Subtotal removal and disposal of contaminated soil	*$196.99*	*$8,601.97*	*$10,046.58*	*$17,400.93*	*$26,790.88*	*$32,569.30*	*$37,756.74*	*$43,338.17*	*$34,079.57*	*$47,278.01*	*$26,002.91*	*$284,062.05*
B. Recontour and seeding												
Recontour and seeding (est. $300/acre)	$2,781.00	$3,510.00	$4,038.00	$7,116.00	$9,525.00	$10,383.00	$15,303.00	$17,376.00	$14,685.00	$24,861.00	$14,463.00	
Subtotal Recontour and Seeding	*$2,781.00*	*$3,510.00*	*$4,038.00*	*$7,116.00*	*$9,525.00*	*$10,383.00*	*$15,303.00*	*$17,376.00*	*$14,685.00*	*$24,861.00*	*$14,463.00*	*$124,041.00*
Total Surface Reclamation	**$2,977.99**	**$12,111.97**	**$14,084.58**	**$24,516.93**	**$36,315.88**	**$42,952.30**	**$53,059.74**	**$60,714.17**	**$48,764.57**	**$72,139.01**	**$40,465.91**	**$408,103.05**
IV. Well Houses												
Total Quantity	0	3	3	5	7	7	6	8	7	8	4	
Average Well House Weight (Lbs.)	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000	6000	
A. Removal												
Dismantlement at 2-man-days per wellhouse (man-days)	0	6	6	10	14	14	12	16	14	16	8	
Dismantlement Labor Costs	$0.00	$918.72	$918.72	$1,531.20	$2,143.68	$2,143.68	$1,837.44	$2,449.92	$2,143.68	$2,449.92	$1,224.96	$17,761.92
Equipment (Cat 924G at 2 hours per wellhouse) (hrs)	0	6	6	10	14	14	12	16	14	16	8	
Equipment Costs	$0.00	$360.36	$360.36	$600.60	$840.84	$840.84	$720.72	$960.96	$840.84	$960.96	$480.48	$6,966.96
Subtotal Well House Dismantlement Costs	*$0.00*	*$1,279.08*	*$1,279.08*	*$2,131.80*	*$2,984.52*	*$2,984.52*	*$2,558.16*	*$3,410.88*	*$2,984.52*	*$3,410.88*	*$1,705.44*	*$24,728.88*
B. Disposal												
Total Disposal Weight (6000 lbs per wellhouse) (Lbs)	0	18000	18000	30000	42000	42000	36000	48000	42000	48000	24000	
Subtotal Disposal Costs	*$0.00*	*$148.86*	*$148.86*	*$248.10*	*$347.34*	*$347.34*	*$297.72*	*$396.96*	*$347.34*	*$396.96*	*$198.48*	*$2,877.96*
Total Well House Removal and Disposal Costs	**$0.00**	**$1,427.94**	**$1,427.94**	**$2,379.90**	**$3,331.86**	**$3,331.86**	**$2,855.88**	**$3,807.84**	**$3,331.86**	**$3,807.84**	**$1,903.92**	**$27,606.84**
TOTAL REMOVAL AND DISPOSAL COSTS PER WELLFIELD	**$43,905.80**	**$110,345.04**	**$170,034.96**	**$301,959.25**	**$525,532.62**	**$484,296.24**	**$506,545.22**	**$720,527.36**	**$582,177.47**	**$402,958.18**	**$274,792.96**	**$4,123,075.10**
TOTAL WELLFIELD BUILDINGS AND EQUIPMENT REMOVAL AND DISPOSAL COSTS	**$4,123,075.10**											

Crow Butte Resources Inc.
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Well Abandonment

			Mine Unit 1	Mine Unit 2	Mine Unit 3	Mine Unit 4	Mine Unit 5	Mine Unit 6	Mine Unit 7	Mine Unit 8	Mine Unit 9	Mine Unit 10	Mine Unit 11	Total
I.	**Well Abandonment (Wellfields)**													
	# of Production Wells		3	52	57	96	187	187	205	248	195	280	140	
	# of Injection Wells		0	79	96	169	221	309	370	412	324	440	256	
	# of Perimeter Monitoring Wells		11	10	7	9	23	26	8	20	13	31	19	
	# of Shallow Monitoring Wells		0	3	3	11	25	28	25	30	20	32	26	
	Total Number of Deep Wells		14	141	160	274	431	522	583	680	532	751	415	4503
	Total Number of Shallow Wells		0	3	3	11	25	28	25	30	20	32	26	203
	Average Diameter of Casing (inches)		5	5	5	5	5	5	5	5	5	5	5	
	Production, Injection and Perimeter Well Average Depth (ft)		665	631	774	698	675	515	762	500	770	480	810	662
	Shallow Well Average Depth (ft)		200	200	200	200	200	200	200	200	200	150	350	209
	Total Mine Unit Well Depth (ft)		9310	89571	124440	193452	295925	274430	449246	346000	413640	365280	345250	2906544
	Well Abandonment Unit Cost ($/ft. of well)		$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	$0.74	
	Subtotal Abandonment Cost per Wellfield		**$6,889.40**	**$66,282.54**	**$92,085.60**	**$143,154.48**	**$218,984.50**	**$203,078.20**	**$332,442.04**	**$256,040.00**	**$306,093.60**	**$270,307.20**	**$255,485.00**	**$2,150,842.56**
II.	**Downhole Pump Disposal**													
	Number of Downhole Pumps	*1020*												
	Pump Disposal Volume(ft3)	0.5												
	Total Pump Disposal Volume(yd3)	18.9												18.9
	Downhole Pump Disposal Rate ($/yd3)	$334.87												334.87
	Subtotal Downhole Pump Disposal		**$6,329.04**											**$6,329.04**
Total Wellfield Abandonment Costs			**$2,157,171.60**											

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Plant Equipment Decommissioning	Commercial Plant	R.O. Building
I. Removal and Loading Costs		
Tankage		
Number of Contaminated Tanks	59	
Volume of Contaminated Tank Construction Material (ft^3)	1139	
Number of Chemical Tanks	9	
Disposal Void Factor	1.25	
A. Labor to Remove and Load Tankage		
Number of Persons	2	
Tanks/Day	1	
Number of Days	68	
$/Day/Person	$153.12	
Subtotal Removal Labor Costs	*$20,824.32*	
B. Labor to Clean Chemical Tankage		
Number of Persons	1	
Tanks/Day	1	
Number of Days	9	
$/Day/Person	$153.12	
Subtotal Cleaning Labor Costs	*$1,378.08*	
C. Equipment		
Saws, scaffolding, etc.	$6,000	
Subtotal Equipment Costs	*$6,000*	
Total Equipment Removal and Loading Costs	**$28,202.40**	
II. Transportation and Disposal Costs (NRC-Licensed Facility)		
A. Tankage		
Volume of Tank Construction Material (ft^3)	1139	
Volume for Disposal Assuming Void Space (yd^3)	52.7	
Transportation and Disposal Unit Cost ($/$yd^3$) (Unpackaged Bulk)	$334.87	
Subtotal Tankage Transportation and Disposal Costs	*$17,647.65*	
B. Contaminated PVC Pipe		
Volume of Shredded PVC Pipe (ft^3)	177.6	
Volume for Disposal Assuming Void Space (yd^3)	8.2	
Transportation and Disposal Unit Cost ($/$yd^3$) (Unpackaged Bulk)	$334.87	
Subtotal Contaminated PVC Pipe Transportation and Disposal Costs	*$2,745.93*	

Plant Equipment Decommissioning

	Commercial Plant	R.O. Building
C. Pumps		
Volume of Process Pumps (yd^3) (no void factor used)	13.3	
Transportation and Disposal Unit Cost ($/$yd^3$) (Unpackaged Bulk)	$334.87	
Subtotal Pump Transportation and Disposal Costs	*$4,453.77*	
D. Filters (injection, backwash and yellowcake filters)		
Volume of Filters (yd^3) (no void factor used)	170.4	
Transportation and Disposal Unit Cost ($/$yd^3$) (Unpackaged Bulk)	$334.87	
Subtotal Filter Transportation and Disposal Costs	*$57,061.85*	
E. Dryer		
Dryer Volume (yd^3) (no void factor used)	29.6	
Transportation and Disposal Unit Cost ($/$yd^3$) (Unpackaged Bulk)	$334.87	
Total Dryer Transportation and Disposal Costs	*$9,912.15*	
Total Contaminated Equipment Transportation and Disposal Costs	**$91,821.35**	
III. Transportation and Disposal (Solid Waste for Landfill Disposal)		
A. Cleaned Tankage		
Volume of Tank Construction Material (ft^3)	174	
Number of Landfill Trips	1	
Transportation and Disposal Unit Cost ($/Load)	$133.75	
Subtotal Tankage Transportation and Disposal Costs	*$133.75*	
B. Uncontaminated PVC Pipe		
Volume of Shredded PVC Pipe (ft^3)	177.6	
Number of Landfill Trips	1	
Transportation and Disposal Unit Cost ($/Load)	$133.75	
Subtotal PVC Pipe Transportation and Disposal Costs	*$133.75*	
Total Uncontaminated Equipment Transportation and Disposal Costs	**$267.50**	
IV. Supervisory Labor Costs During Plant Decommissioning		
Estimated Duration (months)	6	
Engineer	$56,289.90	
Radiation Technician	$28,463.40	
Total Supervisory Labor Costs	**$84,753.30**	
SUBTOTAL EQUIPMENT REMOVAL AND DISPOSAL COSTS PER FACILITY	$205,044.55	
Building Area (Ft2)	34,000	6,875
Building Equipment Removal and Disposal Cost per Square Foot	$6.03	$6.03
TOTAL EQUIPMENT REMOVAL AND DISPOSAL COSTS	**$205,044.55**	**$41,456.25**

Building Demolition	Commercial Plant	R.O. Building
I. Decontamination Costs		
A. Wall Decontamination		
Area to be Decontaminated (ft^2)	25,332	
HCl Application Rate (Gallons/ft^2)	1	
HCl Acid Cost	$1.24	
Subtotal Wall Decontamination Materials Costs	$31,411.68	
B. Concrete Floor Decontamination		
Area to be Decontaminated (ft^2)	18146	
HCl Application Rate (Gallons/ft^2)	2	
HCl Acid Cost	$1.24	
Subtotal Floor Decontamination Materials Costs	$45,002.08	
C. Decontamination Labor		
Labor (man-days)	60	
Subtotal Decontamination Labor Cost	$9,187.20	
D. Decontamination Equipment Costs		
Sprayer pump	$500	
Recycle pump	$500	
Sprayer with hose	$1,000	
Subtotal Decontamination Equipment Costs	$2,000	
E. Decontamination Waste Disposal (to Ponds)		
Total gallons HCl waste	61,624	
Pumping costs (5 HP/30 gpm)	$541.71	
Subtotal Decontamination Costs	$88,142.67	
Total Decontamination Costs	**$88,142.67**	
II. Demolition Costs		
Assumptions (based on 2007 costs):		
Dismantling interior steel, tanks, pumps, etc.	$159,450.00	
Dismantling plant building	$79,725.00	
A. Building Dismantling		
Dismantle interior components (2007 $'s escalated by CPI)	$167,422.50	
Plant building dismantling (2007 $'s escalated by CPI)	$83,711.25	
Subtotal Building Dismantling	*$251,133.75*	
B. Concrete Floor Removal		
Area of direct-dispose concrete floors (ft2)	5,450	

Building Demolition

	Commercial Plant	R.O. Building
Removal Rate ($/ft2)	$14.04	
Subtotal Concrete Floor Removal	*$76,518.00*	
Total Demolition Costs	**$327,651.75**	
III. Disposal Costs		
A. Concrete Floor		
Area of Direct-Dispose Concrete Floor (ft^2)	5,450	
Average Thickness of Concrete Floor (ft)	0.50	
Volume of Concrete Floor (ft^3)	2,725	
Volume of Concrete Floor (Yd3)	101	
Transportation and Disposal Unit Cost ($\$/Yd^3$) (Unpackaged Bulk)	$334.87	
Subtotal Concrete Floor Disposal Costs	*$33,821.87*	
Total Disposal Costs	**$33,821.87**	
IV Plant Site Reclamation		
A. Plant Site Earthwork		
Material to be Moved (Yd3)	20,000	
D8N Bulldozer Earthwork Rate (Yd3/hr)	700	
D8N Hourly Rate	$187.34	
Subtotal Plant Site Earthwork	*$5,352.57*	
B. Revegetation		
Area requiring Revegetation (Ac)	4	
Revegetation Unit Cost ($/Ac)	$300	
Subtotal Plant Site Revegetation	*$1,200.00*	
Total Plant Site Reclamation Costs	**$6,552.57**	
SUBTOTAL BUILDING DEMOLITION AND DISPOSAL COSTS	$456,168.86	
Building Area (Ft2)	34,000	6,875
Building Demolition Cost per Square Foot	$13.42	$13.42
TOTAL BUILDING DEMOLITION AND DISPOSAL COSTS	**$456,168.86**	**$92,262.50**

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Evaporation Pond Reclamation

	Commercial Ponds	R&D Ponds	Total
Assumptions/Data:			
Number of Ponds	3	2	
Area of Ponds (ft2)	250,000	50,000	
Thickness of Liner Material (ft)	0.00833	0.0030	
Leak detection piping size (in)	4	3	
Leak detection piping length (ft/pond)	2,100	600	
Earthwork Requirements (Yd3/pond)	60,000	30,000	
Surface Restoration/Revegetation (Acres)	20	10	
Sludge Production Rate (Yd3 sludge/gal)		0.000000102	
(1 Yd3 sludge/9,772,000 gal R&D Phase)			
Estimated 1991 to 2009 Total Production (gallons)	26,516,468,400		
Liner Removal Rate (ft2/man-day)	10,000	10,000	
Sludge Removal Rate (Yd3/man-day)	8.33	8.33	
I. Pond Liner and Piping Removal			
A. Pond Liner and Piping Removal Labor			
Area of Ponds	750,000	100,000	
Liner Removal Rate (ft2/Man-Day)	10,000	10,000	
Total Man-Days	75	10	
Labor Rate ($/man-day)	$153.12	$153.12	
Subtotal Liner and Piping Removal Labor Costs	*$11,484.00*	*$1,531.20*	*$13,015.20*
B. Pond Liner and Piping Removal Equipment			
Total Man-Days Removal Effort	75	10	
Size of Crew	4	4	
Total Days Removal Effort	18.75	2.5	
Cat 924G Loader Hourly Rate ($/hr)	$60.06	$60.06	
Subtotal Liner and Piping Removal Equipment Costs	*$9,009.00*	*$1,201.20*	*$10,210.20*
Total Pond Liner and Piping Removal Costs	**$20,493.00**	**$2,732.40**	**$23,225.40**

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Evaporation Pond Reclamation				
		Commercial Ponds	R&D Ponds	Total
II.	**Pond Sludge Removal**			
	Pond Sludge Estimate			
	Estimated Production Flow since 1991 (gal)	26,516,468,400		
	Historical Sludge Production Rate	0.000000102		
	Estimated Pond Sludge Volume (Yd3)	2,705	Cleaned following R&D	
	A. Pond Sludge Removal Labor			
	Pond Sludge Volume (Yd3)	2,705		2,705
	Sludge Removal Rate (Yd3/man-day)	8.33		
	Total Man-Days	325		
	Labor Rate ($/man-day)	$153.12		
	Subtotal Pond Sludge Removal Labor Costs	*$49,764.00*	*$0.00*	*$49,764.00*
	B. Pond Sludge Removal Equipment			
	Total Man-Days Removal Effort	325		
	Size of Crew	3		
	Total Days Removal Effort	108		
	Cat 924G Loader Hourly Rate ($/hr)	$60.06		
	Subtotal Pond Sludge Removal Equipment Costs	*$51,891.84*	*$0.00*	*$51,891.84*
	Total Pond Sludge Removal Costs	**$101,655.84**	**$0.00**	**$101,655.84**
III.	**Pond Byproduct Material Disposal**			
	A. Pond Liner Disposal			
	Area of Pond Liner (ft2)	750,000	100,000	
	Thickness of Pond Liner (ft)	0.00833	0.00300	
	Volume of Pond Liner (ft3)	6,248	300	
	Void Space Factor	1.25	1.25	
	Total Disposed Volume (yd3)	289	14	303.0
	Disposal Unit Costs ($/yd3) (Unpackaged Bulk)	$334.87	$334.87	
	Subtotal Pond Liner Disposal Costs	*$96,777.43*	*$4,688.18*	*$101,465.61*

Evaporation Pond Reclamation

	Commercial Ponds	R&D Ponds	Total
B. Pond Piping Disposal			
Total Length of Piping	6,300	1,200	
Piping Volume Factor (ft3/ft)	0.0103	0.0069	
Total Volume Pond Piping (ft3)	65	8	
Void Space Factor	1.25	1.25	
Total Disposed Volume (yd3)	3.0	0.4	3.4
Disposal Unit Costs ($/yd3) (Unpackaged Bulk)	$334.87	$334.87	
Subtotal Pond Piping Disposal Costs	*$1,004.61*	*$133.95*	*$1,138.56*
C. Pond Sludge Disposal			
Total Volume Pond Sludge (Yd3)	2,705		2,705
Disposal Unit Costs ($/yd3) (Soil rate)	$137.87		
Subtotal Pond Sludge Disposal Costs	*$372,938.35*	*$0.00*	*$372,938.35*
Total Byproduct Material Disposal Costs	**$470,720.39**	**$4,822.13**	**$475,542.52**
IV Pond Site Reclamation			
A. Pond Earthwork Requirements			
Earthwork Requirements Yd3)	180,000	60,000	
D8N Bulldozer Earthwork Rate (Yd3/hr)	700	700	
Total D8N Hours	257	86	
D8N Hourly Rate	$187.34	$187.34	
Subtotal Pond Earthwork	*$48,146.38*	*$16,111.24*	*$64,257.62*
B. Revegetation			
Area requiring Revegetation (Ac)	20	10	
Revegetation Unit Cost ($/Ac)	$300.00	$300.00	
Subtotal Plant Site Revegetation	*$6,000.00*	*$3,000.00*	
Total Pond Site Reclamation Costs	**$54,146.38**	**$19,111.24**	$73,257.62

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Evaporation Pond Reclamation			
	Commercial Ponds	**R&D Ponds**	**Total**
V. Supervisory Labor Costs During Pond Reclamation			
Estimated Duration (months)	4		
Engineer Rate ($/month)	$9,381.65		
Total Engineer Labor	$37,526.60		
Radiation Technician Rate ($/month)	$4,743.90		
Total Radiation Technician Labor	$18,975.60		
Total Supervisory Labor Costs	**$56,502.20**	**$0.00**	$56,502.20
TOTAL EVAPORATION POND RECLAMATION PER POND	**$703,517.81**	**$26,665.77**	**$730,183.58**
TOTAL EVAPORATION POND RECLAMATION COSTS	**$730,183.58**		

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Miscellaneous Site Reclamation				
I.	**Access Road Reclamation**			
		Assumptions		
			Road Reclamation production rate (Yd3/hr)	200
			Length of Main Access Roads (ft)	14,900
			Average Main Access Road width (ft)	25
			Depth of Main Access Road Gravel Surface (ft)	1
			Surface Area of Main Access Road (Ac)	8.6
			Length of Wellfield Access Roads (ft)	54,700
			Average Wellfield Access Road width (ft)	12
			Depth of Wellfield Access Road Gravel Surface (ft)	0.5
			Surface Area of Wellfield Road (Ac)	15.1
	A.	Main Access Road Dirtwork		
			Main Access Road Gravel Volume (Yd3)	13,796
			Total reclamation time (hrs)	69
			D8N Unit Operating Cost ($/hr)	$187.34
		Subtotal Main Access Road Gravel Roadbase Removal Costs		*$12,926.46*
	B.	Wellfield Road Dirtwork		
			Wellfield Road Gravel Volume (Yd3)	12,156
			Total reclamation time (hrs)	61
			D8N Unit Operating Cost ($/hr)	$187.34
		Subtotal Wellfield Road Gravel Roadbase Removal Costs		*$11,427.74*
	E.	Discing/Seeding		
			Assumptions	
			Surface Area (acres)	23.7
			Discing/Seeding Unit Cost ($/acre)	$300.00
		Subtotal Discing/Seeding Costs		*$7,110.00*
	Total Access Road Reclamation Costs			**$31,464.20**

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Miscellaneous Site Reclamation					
II.	**Wastewater Pipeline Reclamation**				
		Assumptions			
			Pipeline Removal Rate (ft./man-day)		67
			Pipeline Shredding Rate (ft./man-day)		1,500
			Number of Pond Pipelines		2
			Length of Pond Pipelines (ft)		2,000
			Number of RO Building Pipelines		4
			Length of RO Building Pipelines (ft)		300
			Average Pipe Size (Sch 40)		4
	A.	Pipeline Removal Costs			
			Length of Pipelines (ft)		5,200
			Removal Rate (ft/man-day)		67
			Removal Labor Rate ($/man-day)		$153.12
			Cat 924G Loader Use (days)		78
			Cat 924G Loader Cost		$37,477.44
		Subtotal Pipeline Removal Costs			*$49,420.80*
	B.	Pipeline Shredding Costs			
			Length of Pipelines (ft)		5,200
			Shredding Rate (ft/man-day)		1,500
			Shredding Labor Rate ($/man-day)		$153.12
			Shredder Use (days)		3
			Shredder Cost		$288.00
		Subtotal Pipeline Shredding Costs			*$747.36*

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			Miscellaneous Site Reclamation	
	C.	Pipeline Transportation and Disposal (NRC-Licensed Facility)		
		Pipe Diameter (inches)		4
		Chipped Volume Reduction (ft^3/ft)		0.0103
		Subtotal Volume of Shredded PVC Pipe (yd^3)		2.0
		Disposal Void Factor		1.25
		Final Disposal Volume (yd3)		2.5
		Transportation and Disposal Unit Cost ($/$yd^3$) (Unpackaged Bulk)		$334.87
		Subtotal Pipeline Disposal Costs		*$837.18*
	Total Wastewater Pipeline Reclamation Costs			**$51,005.34**
III.	**Electrical Distribution System Removal**			
		Assumptions		
		Length of High Voltage Lines		43,440
		High Voltage Line Removal Rate ($/ft.)		$0.59
		High Voltage Line Removal Cost ($/ft.)		$25,629.60
		Substation Removal		$1,175.00
		Subtotal Electrical Distribution System Removal Costs		**$26,804.60**
IV.	**Supervisory Labor Costs During Miscellaneous Reclamation**			
		Estimated Duration (months)		3
		Engineer Rate ($/month)		$9,381.65
		Total Engineer Labor		$28,144.95
		Radiation Technician Rate ($/month)		$4,743.90
		Total Radiation Technician Labor		$14,231.70
	Total Supervisory Labor Costs			**$42,376.65**
TOTAL MISCELLANEOUS RECLAMATION COSTS				**$151,650.79**

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Deep Disposal Well Reclamation				
I.	**Cost Basis**			
	A.	Plugging and Abandonment		
			Cost Estimate from March 2004 Permit Re-application for plugging and abandonment	$118,052.00
			March 2004 CPI	187.4
			June 2008 CPI	218.8
		Subtotal Escalated 2003 Plugging and Abandonment Costs		*$137,832.32*
	B.	Site Reclamation		
			Cost Estimate from March 2004 Permit Re-application for site reclamation	$4,866.00
			March 2004 CPI	187.4
			June 2008 CPI	218.8
		Subtotal Escalated 2003 Reclamation Costs		*$5,681.33*
TOTAL DEEP DISPOSAL WELL RECLAMATION COSTS				**$143,513.65**

I-196 Brule Aquifer Restoration					
I.	**Ground Water Sweep Costs**				
	Assumptions				
		PV's Required from I-196a, I-196j and I-196n			3
		Total Gallons per Pore Volume			337,758
		Total Gallons to Treat			1,013,274
		Flow Rate (gpm)			3
		Pump Power Requirements (kwh)			3
		Power Cost ($/kw)			$0.0706
		Pumping Labor (man-day per day) (1hr/day)			0.125
		Sampling Labor (man-day per day) (.5hr/day)			0.0625
		Labor Rate ($/man-day)			$153.12
		Days to complete			235
	A.	Electrical Costs			
		Cost to pump 3 Pore Volumes			*$1,191.61*
	B.	Labor Costs			
		Labor for pumping 3 Pore Volumes			*$4,497.90*
Total Ground Water Sweep Costs					**$5,689.51**
II.	**Monitoring and Sampling Costs**				
	A.	Labor Costs for Monitoring I-196a, I-196j, and I-196n			$2,248.95
	B.	Monitoring for I-196i, I-196m, and I-196l			$2,248.95
Total Monitoring and Sampling Costs					**$4,497.90**

I-196 Brule Aquifer Restoration				
III	**Additional Ground Water Sweep**			
		Pump from additional wells and monitor as above		$10,187.41
		Drill 4 additional wells, 50 ft deep at $26/ft.		$5,200.00
Total Additional Ground Water Sweep				**$15,387.41**
IV	**Well Abandonment**			
		Abandon 14 wells at $194/well		$2,716.00
Total Well Abandonment				**$2,716.00**
TOTAL I-196 BRULE AQUIFER RESTORATION COSTS				**$28,290.82**

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GROUNDWATER RESTORATION
GROUNDWATER IX TREATMENT (GIX) Unit Costs

Assumptions:

1. All pumps are 5 hp pumping at 32 gpm
2. Cost of electricity = $0.0706 Kw hr
3. Horsepower to kilowatt conversion = 0.746 Kw/HP
4. Operator labor costs = $153.12 man-day
5. Labor costs are based on 36 pumps at 1,150 gpm

Wellfield Pumping Electrical Costs per 1000 Gallons

1000	gal	X	5	hp	X	1	hr	X	0.746	kwh	X	$ 0.0706		= $	0.137
			32	gpm		60	min		hp			kwh			

Wellfield Pumping Labor Costs per 1000 Gallons

1000	gal	X	1	min	X	1	man-day	X	$153.12		X	2	operators	= $	$0.555
			1150	gal		480	min		man-day						

Groundwater IX Production Rate

1150	gal	X	60	min	X	24	hr	X	365	day	X	1	year	=	*50,370,000*	*gallons*
	min			hr			day			year		12	month			*month*

TOTAL GWS COSTS PER 1000 GALLONS		**= $**	**0.69**

Groundwater Reverse Osmosis (RO) Treatment Unit Costs

Assumptions:

1.	All pumps are 5 hp pumping at 32 gpm		
2	Membrane Replacement	$0.025	per 1000 gal
3	Cost of electricity =	$0.0706	Kw hr
4	Horsepower to kilowatt conversion =	0.746	Kw/HP
5	Operator labor costs =	$153.12	man-day
6	RO System horsepower requirements for 600 gpm rated flow based upon:		
	RO Unit Pump	170	hp
	Permeate/Injection pump	60	hp
	Waste pump	12	hp
	TOTAL:	242	hp
7	Chemical costs:		
	Reductant =	$0.39	lb
	Antiscalant =	$17.64	gal

Membrane Replacement Costs per 1000 Gallons

1000	gal	X	$660	membrane	/	26,280,000	gallons							= $	0.025	per Kgal
				cost / month			month									

Wellfield Pumping Electrical Costs per 1000 Gallons

1000	gal	X	5	hp	X	1	hr	X	0.746	kwh	X	$ 0.0706		= $	0.137	per Kgal
			32	gpm		60	min		hp			kwh				

Reverse Osmosis Electrical Costs per 1000 Gallons

1000	gal	X	242	hp	X	1	hr	X	0.746	kwh	X	$ 0.0706		= $	0.354	per Kgal
			600	gpm		60	min		hp			kwh				

Reverse Osmosis Labor Costs per 1000 Gallons

1000	gal	X	1	min	X	1	man-day	X	$153.12		X	2	operators	= $	$1.063	per Kgal
			600	gal		480	min		man-day							

Treatment chemical costs per 1000 Gallons

Antiscalant:																
1000	gal	X	0.000008330	gal antiscalant	X	$17.64								= $	$0.147	per Kgal
			1	gal		gal antiscalant										
Reductant:																
1000	gal	X	0.000560	lbs reductant	X	$0.387								= $	$0.217	per Kgal
			1	gal		lb reductant										

Reverse Osmosis Production Rate

600	gal	X	60	min	X	24	hr	X	365	day	X	1	year	=	*26,280,000*	*gallons*
	min			hr			day			year		12	month			*month*

TOTAL RO COSTS PER 1000 GALLONS = $ **1.94**

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Groundwater Recirculation Unit Costs

Assumptions:

1. All pumps are 5 hp pumping at 32 gpm
2. Cost of electricity = $0.0706 Kw hr
3. Horsepower to kilowatt conversion = 0.746 Kw/HP
4. Operator labor costs = $153.12 man-day
5. System horsepower requirements for 1,150 gpm rated flow based upon:

injection pump	30	hp

Wellfield Pumping Electrical Costs per 1000 Gallons																	
	1000	gal	X	5	hp	X	1	hr	X	0.746	kwh	X	$ 0.0706		= $	0.137	per Kgal
				32	gpm		60	min		hp			kwh				
Wellfield Injection Electrical Costs per 1000 Gallons																	
	1000	gal	X	30	hp	X	1	hr	X	0.746	kwh	X	$ 0.0706		= $	0.023	per Kgal
				1150	gpm		60	min		hp			kwh				
Recirculation Labor Costs per 1000 Gallons																	
	1000	gal	X	1	min	X	1	man-day	X	$153.12		X	2	operators	= $	0.555	per Kgal
				1150	gal		480	min		man-day							
Recirculation Production Rate																	
	1150	gal	X	60	min	X	24	hr	X	365	day	X	1	year	=	*50,370,000*	*gallons*
		min			hr			day			year		12	month			*month*
TOTAL RECIRCULATION COSTS PER 1000 GALLONS													= $	0.72			

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WELL ABANDONMENT Unit Costs

Assumptions:												
1	Use backhoe for 0.25 hr/well to dig, cut off, and cap well.											
2	Drill rig used 2.5 hrs to plug well.											
3	Labor for installing chips, etc. will require 2 workers at 0.5 hrs per well											
Well Abandonment Costs											**Cost per ft (based on 700 ft wells)**	
	Labor Costs	1	hours	X	$	19.14	per hour		=$	19.14	$0.0273	
	Cat 416 Backhoe											
		0.25	hours	X	$	50.35	per hour		=$	12.59	$0.0180	
	Drill rig											
		2.5	hours	X	$	155.00	per hour		=$	387.50	$0.5536	
	Well Cap	1	each	X	$	8.37	each		=$	8.37	$0.0120	
Materials per foot of well (Variable Cost)												
	Cement	0.0714	lbs/ft	X	$	0.070	per pound		=$		$0.0050	
	Bentonite Chips	0.007	tubes/ft	X	$	8.50	per tube		=$		$0.0595	
	Plug Gel	0.0086	sacks/ft	X	$	7.15	per sack		=$		$0.0615	
Total Estimated Cost per Foot:											**$0.74**	

Crow Butte Resources, Inc.
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Master Cost Basis

Mine Unit Data

		Mine Unit 1	Mine Unit 2	Mine Unit 3	Mine Unit 4	Mine Unit 5	Mine Unit 6	Mine Unit 7	Mine Unit 8	Mine Unit 9	Mine Unit 10	Mine Unit 11
Total number of production wells		3	52	57	96	187	187	205	248	195	280	140
Total number of injection wells		0	79	96	169	221	309	370	412	324	440	256
Total number of shallow monitor wells		0	3	3	11	25	28	25	30	20	32	26
Total number of perimeter monitor wells		11	10	7	9	23	26	8	20	13	31	19
Total number of restoration wells		10	12	18	43	33	29	25	30	21	32	24
Wellfield Area (ft2)		403,712	509,600	586,188	1,033,405	1,383,005	1,507,647	2,222,190	2,522,911	2,132,355	3,610,000	2,100,000
Wellfield Area (acres)		9.27	11.70	13.46	23.72	31.75	34.61	51.01	57.92	48.95	82.87	48.21
Affected Ore Zone Area (ft2)		403,712	509,600	586,188	1,033,405	1,383,005	1,507,647	2,222,190	2,522,911	2,132,355	3,610,000	2,100,000
Avg. Completed Thickness		19.6	16.3	12.5	12.9	14.6	15.4	12.3	16.4	16.4	18	22
Porosity		0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Affected Volume (ft3)		7,912,755	8,306,480	7,327,350	13,330,925	20,191,873	23,217,764	27,332,937	41,375,740	34,970,622	64,980,000	46,200,000
Kgallons per Pore Volume		17,164	18,018	15,894	28,917	43,800	50,364	59,291	89,752	75,858	140,955	100,217
Number of Patterns in Unit(s)												
	Current	0	52	57	96	187	187	205	248	195	260	120
	Estimated next report	0	0	0	0	0	0	0	0	0	20	20
	Total Estimated	0	52	57	96	187	187	205	248	195	280	140
Number of Wells in Unit(s)												
Production Wells												
	Current	3	52	57	96	187	187	205	248	195	260	120
	Estimated next report	0	0	0	0	0	0	0	0	0	20	20
	Total Estimated	3	52	57	96	187	187	205	248	195	280	140
Injection Wells												
	Current	0	79	96	169	221	309	370	412	324	430	200
	Estimated next report	0	0	0	0	0	0	0	0	0	10	56
	Total Estimated	0	79	96	169	221	309	370	412	324	440	256
Shallow Monitor Wells												
	Current	0	3	3	11	25	28	25	30	20	32	26
	Estimated next report	0	0	0	0	0	0	0	0	0	0	0
	Total Estimated	0	3	3	11	25	28	25	30	20	32	26
Perimeter Monitor Wells												
	Current	11	10	7	11	23	26	8	20	20	31	19
	Estimated next report	0	0	0	-2	0	0	0	0	-7	0	0
	Total Estimated	11	10	7	9	23	26	8	20	13	31	19
Number of Wells per Wellfield		14	144	163	285	456	550	608	710	552	783	441
Total Number of Wells		4706										
Average Well Depth (ft) - Deep Wells		665	631	774	698	675	515	762	500	770	480	810
Average Well Depth (ft) - Shallow Wells		200	200	200	200	200	200	200	200	200	150	350

Crow Butte Resources, Inc.
Crow Butte Uranium Project 2009 Surety Estimate
(Revised February 2009)

Master Cost Basis

Electrical Costs			
	2008 Rate	2009 Est Rate	
Power cost (adj for current actual cost)	$0.0672	$0.0706	kwHr
Kilowatt to Horsepower	0.746	0.746	Kw/HP
Horsepower per gallon per minute	0.167	0.167	HP/gpm
Labor Rates			
	2008 Rate	2009 Est Rate (CPI)	
Operator Labor Cost	$145.83	$153.12	day
Engineer Cost	$8,934.90	$9,381.65	month
Radiation Technician Costs	$4,518.00	$4,743.90	month
Chemical Costs			
	2008 Rate	2009 Est Rate	
Antiscalant for RO (adj for current actual cost)	$16.80	$17.64	gal
Reductant (adj for current actual cost)	$0.37	$0.39	lb
Cement (adj for current actual cost)	$0.06	$0.07	pound
Bentonite Tubes (adj for current actual cost)	$3.72	$8.50	tube
Salt (adj for current actual cost)	$110.00	$112.80	ton
Plug Gel (adj for current actual cost)	$7.55	$7.15	sack
Well Cap (adj for current actual cost)	$7.67	$8.37	each
Hydrochloric Acid (adj for current actual cost)	$1.20	$1.24	gallon
Analytical Costs			
Guideline 8 (contract lab adjusted for current contract cost)	$200.00	$200.00	analysis
6 parameter (in-house) Est Rate (CPI)	$50.50	$53.03	analysis
Other (radon, bio, etc.) Est Rate (CPI)	$925.00	$971.25	month
Spare Parts			
	2008 Rate	2009 Est Rate (CPI)	
Restoration spare parts estimate	$19,500.00	$20,475.00	year

CPI Escalators (CPI-U, U.S. City Average)	
1988 CPI (average)	118.3
March 2004 CPI (deep well estimate)	187.4
2007 CPI (June 2007 used in last update)	208.4
Current CPI (June 2008)	218.8
2008 Escalation Factor	1.050

Equipment Costs

Equipment	Base Rental Rate ($/hr)	Labor Costs ($/hr)	Repair Reserve Costs ($/hr)	Fuel Costs ($/hr)	Mob & Demob ($/hr)	Total ($/hr)
Cat 924G Loader	$26.50	$18.23	$3.12	$12.21	inc.	$60.06
Cat 416 Backhoe	$16.50	$18.23	$3.00	$12.62	inc.	$50.35
Shredder	$12.00			inc	inc	$12.00
Cat D8N Bulldozer	$110.00	$18.23	$12.30	$46.81	inc.	$187.34
Pulling Unit	$37.50	inc	inc	inc	inc	$37.50
Mixing Unit	$5.00			inc	inc	$5.00
Drill Rig	$155.00	inc	inc	inc	inc	$155.00

Basis:
Cat 924G, 416 and D8N rental rates from Nebraska Machinery (Aug '08); others estimated.
Repair Reserve costs based on from Nebraska Machinery (Aug '08).
Current diesel usage from from Nebraska Machinery (Aug 08), with current (Aug 08) costs for off-road fuel: $4.070 gallon

Labor rate based on current operator labor rate

Pipe Volumes

Nominal Pipe Size	Wall Thickness (in.)	Pipe OD (in.)	Volume per foot (ft3/ft)
3/8-inch O2 hose		0.37500	0.03130
2-inch Sch. 40 downhole	0.15400	2.37500	0.00740
1-1/4-inch Sch. 40 stinger	0.14000	1.66000	0.00440
2-inch SDR 13.5 inj & prod.	0.14815	2.29630	0.00690
4-inch SDR 35	0.11430	4.22860	0.01030
6-inch Sch. 40 process pipe	0.28000	6.56000	0.03840
6-inch Trunkline	0.49100	6.56600	0.06510
8-inch Trunkline	0.63900	8.54800	0.11030
10-inch Trunkline	0.79600	10.65400	0.17120
12-inch Trunkline	0.94400	12.63700	0.24080

Pipe Removal and Shredding Costs

Activity	Removal Rate (ft/man-day)	Shredding Rate (ft/man-day)	Labor Rate (day)	Activity Cost per foot
2-inch SDR 13.5 inj & prod. Removal	225		$153.12	$0.68
2-inch SDR 13.5 inj & prod. Shredding		1920	$153.12	$0.08
Trunkline Removal	100		$153.12	$1.53
Trunkline Shredding		100	$153.12	$1.53
Downhole Pipe Removal	2000		$153.12	$0.08
Downhole Pipe Shredding		2250	$153.12	$0.07
Downhole Hose Removal	1000		$153.12	$0.15
Waste and RO Building Pipeline Removal	67		$153.12	$2.29
Waste and RO Building Pipeline Shredding		1500	$153.12	$0.10

Waste Disposal Costs

Waste Form	Fee		Density Correction Factor (Tons/Yd3)	Fee per Cubic Yard	Transport Cost		Total Transportation and Disposal	
Soil, Bulk Byproduct Material	$185.19	per Ton	0.54	$100.00	$37.87	per Yd3	$137.87	per Yd3
Unpackaged Bulk Byproduct Material (e.g., pipe, equipment)	$707.15	per Ton	0.42	$297.00	$37.87	per Yd3	$334.87	per Yd3
Solid Waste (landfill)	$0.00827	per Lb			Incl.	per Lb	$0.00827	per Lb
Solid Waste (landfill)	$133.75	per Load			Incl.	per Load	$133.75	per Load
Void Factor (for disposal)	1.25							

Plant Dismantling

Plant Components:	*Number*	*Units*	*Estimated Disposal Volume*	*Units*	*Activity*	*Units*	*2007 Cost*
Contaminated Tanks	59	each	19.3	Ft3 each	Dismantle interior steel, tanks, piping and electrical:		$ 159450
Uncontaminated Tanks	9	each	19.3	Ft3 each	Dismantle Plant Building		$ 79725
Pumps	72	each	5	Ft3 each			
Downhole Pumps	1020	each	0.5	Ft3 each	Concrete floor removal rate	Current Cost $/ft2	14.04
Contaminated Piping	4625	feet					
Uncontaminated Piping	4625	feet	See estimate by piping size and material				
Filters	46	each	100	Ft3 each			
Dryer	2	each	400	Ft3 each			
Average PVC Pipe Diameter (inches)	6						

Plant Decontamination

Direct Dispose Plant Floor Area	5450	ft2	Decon Solution (HCl) Floor Application Rate	2	gal/ft2
Uncontaminated Plant Floor Area	7000	ft2			
Decontaminated Plant Floor Area*	18146	ft2			
Average concrete thickness	0.5	ft			
Plant Wall Area	25332	ft2	Decon Solution (HCl) Wall Application Rate	1	gal/ft2

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EcoNomics

Wellfield Restoration Modeling
Crow Butte Resources Mine Units 2-5

Cameco Resources, Crow Butte Operations
Crawford, Nebraska

19 February 2009

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INTRODUCTION

This report summarizes results of wellfield restoration modeling conducted at Crow Butte Resources Mine Units 2-5. The purpose of the modeling was to assist Cameco with restoration planning by optimizing the restoration plan for each Mine Unit (MU). To accomplish this objective, a three-dimensional groundwater flow model of the Crow Butte permit area and surrounding region was developed for the purpose of optimizing restoration well locations, injection and extraction rates, and the overall restoration sequence for each Mine Unit.

GROUND WATER FLOW MODEL

Groundwater flow at the Crow Butte facility was simulated using MODFLOW2000[1], a three-dimensional groundwater flow model developed by the United States Geological Survey. The model domain covers an area of approximately 56 square miles and includes the entire current Crow Butte license area (Figure 1). The flow model grid consists of 374 rows, 313 columns, and 6 layers. The grid spacing varies from 25-feet in the vicinity of mine units to approximately 2000 feet in areas outside the current license boundary.

Boundary Conditions

The basal Chadron Sandstone, or mined interval, was divided into three layers (4, 5 and 6) to accommodate the roll-front geometry of the ore deposits and variable well construction (open/mined interval). The overlying alluvial sands, Brule Formation, and Chadron Formation clays are represented by shallow layers 1, 2 and 3, respectively.

Boundary conditions for the groundwater flow model were developed from pre-mining water level data collected as part of the original Crow Butte permit application, in conjunction with regional water level data compiled by the U.S. Geological Survey and University of Nebraska-Lincoln (Figure 2). These data indicate groundwater flows from recharge/outcrop areas south of the site in a north-northwest direction through the permit area. Groundwater in the shallow alluvial aquifer and Brule Sand aquifer discharges locally at the White River near Crawford. Groundwater in the basal Chadron Sandstone discharges at outcrop locations north of Crawford and in the White River valley northeast of the model area.

Groundwater flow is constrained by streamline (no flow) boundaries on the eastern and western model boundaries. Groundwater inflow from outcrop areas are specified as Constant Head boundaries along the southern model boundary. Groundwater discharge or outflow is simulated by Constant Head boundaries to the north of the license area.

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[1] Harbaugh, A. W., Banta, E. R., Hill, M. C., and McDonald, M. G. (2000). MODFLOW-2000, The U.S. Geological Survey Modular Groundwater Flow Model – User Guide to Modularization Concepts and the Ground-water Flow Process, U.S. Geological Survey Open File Report 00-92.

Aquifer Properties

Information concerning the aquifer properties of the basal Chadron Sandstone, including hydraulic conductivity, porosity, and storativity were obtained from four aquifer test reports prepared as part of the mine unit permit applications. Information concerning the porosity of the basal Chadron Sand, and the vertical hydraulic conductivity of the overlying Chadron Formation and underlying Pierre Shale were obtained from core testing data summarized in the aquifer test reports. In general, the basal Chadron Sandstone is fairly uniform, with hydraulic conductivity varying by less than a factor of four (from 7 to 27 ft/day) across the entire license area, with an average conductivity of approximately 9 ft/day. Porosity of the basal Chadron Sandstone varies from approximately 0.25 to 0.29. Groundwater recharge to the basal Chadron Sandstone is limited to leakage of groundwater from the overlying Chadron Formation clays and the underlying Pierre Shale of very low permeability.

Flow model calibration

Model calibration is the process whereby aquifer properties and boundary conditions are adjusted over a reasonable range of values in order to obtain a close match between modeled and observed conditions (water levels and flows). Flow model calibration is necessary for a model to produce reliable results and make predictions with a reasonable degree of confidence.

The groundwater flow model was calibrated to pre-mining conditions using water level data collected prior to the mining activities in January of 1983. Initial estimates of aquifer properties and boundary water levels were adjusted slightly as part of the model calibration process in order to achieve the best possible match between observed and simulated water levels. Adjustments were primarily confined to constant head elevations along the southern model boundary.

Results of the flow model calibration are provided in Table 1 and Figure 2. A contour map showing the calibrated water level elevation in the Basal Chadron Sand is provided in Figure 3.

WELLFIELD RESTORATION

The calibrated groundwater flow model was used to optimize restoration in MU2-MU5 given certain practical limitations on treatment rate, disposal capacity, and existing well injection and extraction rates. Restoration is planned to proceed in general accordance with permit conditions, to involve recovery of affected groundwater, treatment by Ion Exchange (IX) and Reverse Osmosis (RO), and injection of RO permeate into the wellfield.

Restoration Constraints

Wellfield restoration simulations were largely constrained by the Reverse Osmosis treatment rate, which limits the maximum injection rate available for restoration. Current sustainable RO treatment capacity is estimated to be 500-600 gpm with approximately 75% efficiency (25% bleed for disposal), with some additional decrease in treatment rate due to downtime for maintenance. Based on these estimates, a 400 gpm target RO treatment/injection rate was assumed for purposes of restoration simulations.

Conceptual Restoration Objectives

Because of the close proximity of neighboring mine units at the Crow Butte facility, bleed rates of 2-5% (typically less than 20 gpm per restoration unit at 400 gpm treatment/injection rate) are considered optimal. This will ensure a sufficient area is treated, and should also ensure that neighboring mine units and wellfields are not negatively influenced by restoration activities.

Restoration Sequence

Restoration was simulated in the following sequence (for practical reasons and based on results of this modeling):

- Phase I – Resume restoration of MU2 (four months)
- Phase II – Resume restoration of MU3, complete restoration of MU2 and enter stabilization (2 months)
- Phase III – Complete restoration MU3, enter stabilization (6 months)
- Phase IV – Restoration of eastern half of MU4, enter stabilization (6 months)
- Phase V – Restoration of western half of MU4, enter stabilization (4 months)
- Phase VI – Restoration of eastern portion of MU5, enter stabilization (6 months)
- Phase VII – Restoration of western portion of MU5, enter stabilization (4 months)
- Phase VIII – Restoration of northern portion of MU5, enter stabilization (6 months)

RESTORATION SIMULATION AND OPTIMIZATION

Methodology

The objective of the wellfield restoration modeling is to find the optimal configuration of injection and extraction wells (number, location, and injection/extraction rate) that achieves maximum treatment in the shortest possible time. To accomplish this objective, the calibrated groundwater flow model was used to simulate groundwater flow, and the particle-tracking model MODPATH[2] was used to determine the area of the wellfield being treated (restored) over time. This process was facilitated by employing an automated well optimization procedure[3] that simulates a large number of possible well configurations and compares the number of particles captured by extraction wells as a means of determining which of the configurations offers the most efficient restoration. Results of the most

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[2] Pollack, D.W. (1994). A Users Guide for MODPATH/MODPATH-PLOT, Version 3; A particle-tracking post-processing package for MODFLOW, the U.S. Geological Survey finite-difference ground-water flow model, U.S. Geological Survey Open File Report 94-464.

[3] Environmental Simulations, Inc (2000). Users Guide for BRUTE FORCE version 2.1, a wellfield optimization program.

promising simulations were compared visually (e.g. by comparison of particle traces) and final modifications were made to ensure an optimal restoration scheme.

Phase I Simulations (MU2)

Phase I wellfield restoration will involve the restoration of MU2. The wellfield configuration that achieved the best overall restoration in the shortest time is illustrated in Figure 4. Optimized well locations and associated injection and extraction rates are provided in Table 2. The optimal configuration includes 18 injection wells and 13 extraction wells operating for four months. This scenario assumes injection of 360 gpm of treated water, with extraction of 365 gpm (1.4% bleed) for treatment.

The distribution of particle traces in Figure 4 demonstrates that more than 90% of the wellfield have been effectively treated over a 4 month simulation period, which corresponds to approximately 3.8 pore volumes treated. Results of this simulation, in conjunction with theoretical considerations, historical restoration data, and the most recent wellfield sampling information (August 2008), suggest that restoration of MU2 should be achieved by the end of the 4 month simulation period.

Phase II and III Simulations (MU3)

Phase II and III wellfield restoration will involve restoration of Mine Unit 3. The wellfield configuration that achieved the best overall restoration in the shortest time is illustrated in Figure 5. Optimized well locations and associated injection and extraction rates for Phase II and III are provided in Table 3. The optimal configuration for Phase II and III includes 21 injection wells and 7 extraction wells in MU3 operating for a total of eight months. This scenario assumes injection of 246 gpm of treated water, with extraction of 218 gpm from wells in MU3. Over-injection of treated water into MU3 is needed to address instability issues in MU1.

The distribution of particle traces in Figure 5 demonstrates that more than 90% of the wellfield have been effectively treated over the 8 month simulation period. This corresponds to approximately 4.4 pore volumes treated for MU3. Results of this simulation and theoretical considerations suggest that restoration of MU3 should be achieved by the end of the 8 month simulation period.

Phase IV Simulations (MU4, Eastern Half)

Phase IV wellfield restoration will involve the restoration of the eastern half of MU4. The wellfield configuration that achieved the best overall restoration in the shortest time is illustrated in Figure 6. Optimized well locations and associated injection and extraction rates for are provided in Table 4. The optimal configuration includes 41 injection wells and 22 extraction wells operating for 6 months. This scenario assumes injection of 396 gpm of treated water, with extraction of 402 gpm (1.5% bleed) for treatment.

The distribution of particle traces in Figure 6 demonstrates that more than 90% of the wellfield have been effectively treated over a 6 month simulation period, which corresponds to approximately 6.0 pore volumes treated. Results of this simulation and theoretical considerations suggest that restoration should be achieved by the end of the 8 month simulation period.

Phase V Simulations (MU4, Western Half)

Phase V wellfield restoration will involve the restoration of the western half of MU4. The wellfield configuration that achieved the best overall restoration in the shortest time is illustrated in Figure 7. Optimized well locations and associated injection and extraction rates for are provided in Table 5. The optimal configuration includes 24 injection wells and 18 extraction wells operating for 4 months. This scenario assumes injection of 392 gpm of treated water, with extraction of 400 gpm (2% bleed) for treatment.

The distribution of particle traces in Figure 7 demonstrates that more than 90% of the wellfield have been effectively treated over a 4 month simulation period, which corresponds to approximately 4.8 pore volumes treated. Results of this simulation and theoretical considerations suggest that restoration should be achieved by the end of the 4 month simulation period.

Phase VI Simulations (MU5, Eastern Portion)

Due to the large size of MU5 (roughly three times the pore volume size of MU2) it was deemed most efficient to break the restoration of MU5 into three pieces – the eastern portion, western portion, and northern portion – in three separate phases.

Phase VI wellfield restoration will involve the restoration of the eastern portion of MU5. The wellfield configuration that achieved the best overall restoration in the shortest time is illustrated in Figure 8. Optimized well locations and associated injection and extraction rates for are provided in Table 6. The optimal configuration includes 25 injection wells and 13 extraction wells operating for 6 months. This scenario assumes injection of 267 gpm of treated water, with extraction of 272 gpm (1.8% bleed) for treatment.

The distribution of particle traces in Figure 8 demonstrates that more than 90% of the wellfield have been effectively treated over a 6 month simulation period, which corresponds to approximately 4.9 pore volumes treated. Results of this simulation and theoretical considerations suggest restoration should be achieved by the end of the 6 month simulation period.

Phase VII Simulations (MU5, Western Portion)

Phase VII wellfield restoration will involve the restoration of the western portion of MU5. The wellfield configuration that achieved the best overall restoration in the shortest time is illustrated in Figure 9. Optimized well locations and associated injection and extraction rates for are provided in Table 7. The optimal configuration includes 23 injection wells and 17 extraction wells operating for 4 months. This scenario assumes injection of 345 gpm of treated water, with extraction of 351 gpm (1.7% bleed) for treatment.

The distribution of particle traces in Figure 9 demonstrates that more than 90% of the wellfield have been effectively treated over a 4 month simulation period, which corresponds to approximately 4.3 pore volumes treated. Results of this simulation and theoretical considerations suggest restoration should be achieved by the end of the 4 month simulation period.

Phase VIII Simulations (MU5, Northern Portion)

Phase VIII wellfield restoration will involve the restoration of the northern portion of MU5. The wellfield configuration that achieved the best overall restoration in the shortest time is illustrated in Figure 10. Optimized well locations and associated injection and extraction rates are provided in Table 8. The optimal configuration includes 48 injection wells and 19 extraction wells operating for 6 months. This scenario assumes injection of 353 gpm of treated water, with extraction of 360 gpm (1.9% bleed) for treatment.

The distribution of particle traces in Figure 10 demonstrates that more than 90% of the wellfield have been effectively treated over a 6 month simulation period, which corresponds to approximately 6.5 pore volumes treated. Results of this simulation and theoretical considerations suggest restoration should be achieved by the end of the 6 month simulation period.

Table 1. Flow Model Calibration Statistics, Modeled Vs. Observed Water Levels, January 1983

Name	X	Y	Layer	Observed	Computed	Weight	Group	Residual
well1	1099888	488363.3	4	3756.2	3757.36773	1	1	-1.167727
well2	1096019	493553.4	4	3755.6	3753.98576	1	1	1.614241
well3	1100428	499469.1	6	3752.9	3750.94347	1	1	1.956526
well4	1090531	503450	4	3746.6	3744.82302	1	1	1.776979
well5	1091852	504863.8	4	3746.3	3743.23794	1	1	3.062056
well6	1093359	509812.1	4	3732	3732.69845	1	1	-0.69845
well7	1083525	515355.7	4	3715.2	3717.37891	1	1	-2.178913
well7	1083521	515355.7	6	3715.2	3717.37645	1	1	-2.176447
well7	1083518	515355.7	5	3715.2	3717.37482	1	1	-2.174819
well6	1093359	509812.1	6	3732	3732.69845	1	1	-0.69845
well6	1093359	509812.1	5	3732	3732.69845	1	1	-0.69845
well5	1091852	504863.8	6	3746.3	3743.23794	1	1	3.062056
well5	1091852	504863.8	5	3746.3	3743.23794	1	1	3.062056
well4	1090531	503450	6	3746.6	3744.82302	1	1	1.776979
well4	1090531	503450	5	3746.6	3744.82302	1	1	1.776979
well3	1100501	499469.1	4	3752.9	3750.96849	1	1	1.931508
well3	1100428	499469.1	5	3752.9	3750.94347	1	1	1.956526
well2	1096019	493553.4	6	3755.6	3753.98576	1	1	1.614241
well2	1096019	493553.4	5	3755.6	3753.98576	1	1	1.614241
well1	1099888	488363.3	6	3756.2	3757.36773	1	1	-1.167727
well1	1099888	488363.3	5	3756.2	3757.36773	1	1	-1.167727
Residual Mean						0.622651		
Res. Std. Dev.						1.805186		
Sum of Squares						76.57423		
Abs. Res. Mean						1.777767		
Min. Residual						-2.17891		
Max. Residual						3.062056		
Range in Target Values						41		
Std. Dev./Range						0.044029		

Table 2. Phase I Restoration Simulation Results

MU2 Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Duration (days)	Comments
P124i	Injection	1099057	495729	22.2	120	
I155	Injection	1099062	496210	25.0	120	
I133	Injection	1098676	496467	10.0	120	
I142	Injection	1098834	496518	20.0	120	
I131	Injection	1098640	496297	21.0	120	
I153	Injection	1098971	496332	24.0	120	
I143	Injection	1098959	496586	13.0	120	
I169	Injection	1099623	495621	6.0	120	
I170	Injection	1099036	496042	10.0	120	
I177	Injection	1099597	495465	10.0	120	
I184	Injection	1099104	495958	27.0	120	
I197	Injection	1099307	495809	27.0	120	
I198	Injection	1099615	495771	27.0	120	
I202	Injection	1099161	495632	18.0	120	
I206	Injection	1099389	495534	28.0	120	
P117i	Injection	1099101	495816	22.2	120	
P85i	Injection	1098804	496254	22.2	120	
I138	Injection	1099557	495900	27.0	120	
P97	Extraction	1099530	495590	-29.0	120	
P119	Extraction	1099337	495680	-36.0	120	
P83	Extraction	1098832	496385	-30.0	120	
P121	Extraction	1099453	495737	-24.0	120	
P110	Extraction	1099253	495922	-32.0	120	
P112	Extraction	1099435	495999	-11.0	120	
P210	Extraction	1099487	495932	-30.0	120	
P105	Extraction	1099265	496046	-26.0	120	
P98	Extraction	1099152	496158	-30.0	120	
P92	Extraction	1099130	496330	-31.0	120	
P91	Extraction	1099083	496442	-27.0	120	
P88	Extraction	1098939	496417	-29.0	120	
P84	Extraction	1098725	496391	-30.0	120	

Table 3. Phase II and III Restoration Simulation Results

MU3 Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Period of Operation (days)	Comments
I270	Injection	1098153	496464	10.0	180	
I271	Injection	1098228	496330	10.0	180	
I299	Injection	1098102	496155	26.0	180	
I318	Injection	1098107	495971	5.0	180	
P254i	Injection	1098129	495776	10.0	180	
I366	Injection	1098285	495496	10.0	180	
I367	Injection	1098166	495501	10.0	180	
I361	Injection	1098047	495549	7.0	180	
I360	Injection	1097923	495594	5.2	180	
I350	Injection	1097797	495640	10.0	180	
I347	Injection	1097603	495592	10.0	180	MU4 Well
I339	Injection	1097419	495636	10.0	180	MU7 Well
I340	Injection	1097432	495780	10.0	180	
I337	Injection	1097401	495855	10.0	180	
I333	Injection	1097401	495988	10.0	180	
I332	Injection	1097469	496036	10.0	180	
I309	Injection	1097429	496205	5.0	180	
I336	Injection	1097549	496264	14.0	180	
I284	Injection	1097648	496425	6.0	180	
I281	Injection	1097777	496360	10.0	180	
I275	Injection	1098027	496492	8.0	180	
P222	Extraction	1098056	496314	-29.0	180	
P228	Extraction	1097831	496239	-45.0	180	
P232	Extraction	1097736	496058	-35.0	180	
P235	Extraction	1097924	496044	-23.0	180	
I343P	Extraction	1097626	495812	-30.0	180	
P259	Extraction	1097904	495809	-36.0	180	
I355P	Extraction	1098114	495699	-20.0	180	

Table 4. Phase IV Restoration Simulation Results

MU4 (East Half) Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Period of Operation (days)	Comments
I505	Injection	1099875	495614	9.0	180	
I509	Injection	1099972	495412	35.1	180	
P423I	Injection	1099481	495117	13.3	180	
I591	Injection	1100059	494611	10.4	180	
I594	Injection	1099888	494831	13.3	180	
I596	Injection	1100163	494911	13.3	180	
P376I	Injection	1099211	495569	6.7	180	
P378I	Injection	1099096	495609	6.7	180	
P390I	Injection	1100150	495295	6.7	180	
P403I	Injection	1100667	494642	6.7	180	
P411I	Injection	1100250	494575	6.7	180	
P464I	Injection	1100491	495091	15.6	180	
P469I	Injection	1100733	494490	6.7	180	
I506	Injection	1099975	495539	6.7	180	
I512	Injection	1099655	495408	20.0	180	
I514	Injection	1099256	495451	10.0	180	
I517	Injection	1099327	495420	6.7	180	
I522	Injection	1099025	495607	6.7	180	
I527	Injection	1099397	495129	6.7	180	
I529	Injection	1099201	495338	6.7	180	
I533	Injection	1099838	495178	18.2	180	
I535	Injection	1100326	495145	13.0	180	
I538P	Injection	1100287	494953	15.0	180	
I555	Injection	1100241	495290	6.7	180	
I562	Injection	1100627	494991	5.0	180	
I568	Injection	1100570	494731	18.0	180	
I569	Injection	1100658	494705	6.7	180	
I570	Injection	1100739	494585	6.7	180	
I572	Injection	1100614	494504	6.7	180	
I575	Injection	1100790	494309	6.7	180	
I577	Injection	1100607	494341	6.7	180	
I584	Injection	1100395	494384	6.7	180	
I586	Injection	1100408	494667	15.0	180	
I592	Injection	1100003	494670	6.7	180	
I600	Injection	1099758	495151	7.8	180	
I603	Injection	1099862	494967	5.0	180	
I604	Injection	1099803	494839	6.7	180	
I605	Injection	1099747	494901	6.7	180	
I607	Injection	1099626	494978	6.7	180	
I608	Injection	1099621	495118	5.0	180	
I611	Injection	1099525	495047	6.7	180	

MU4 (East Half) Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Period of Operation (days)	Comments
P375	Extraction	1099321	495492	-13.0	180	
P377	Extraction	1099193	495515	-20.8	180	
P398	Extraction	1100579	495021	-23.0	180	
P396	Extraction	1100300	495196	-15.6	180	
P397	Extraction	1100103	495311	-24.0	180	
P372	Extraction	1099684	495583	-20.8	180	
P387	Extraction	1099264	495295	-13.0	180	
P392	Extraction	1100461	494525	-15.0	180	
P404	Extraction	1100581	494584	-22.0	180	
P407	Extraction	1100703	494444	-26.0	180	
P412	Extraction	1100311	494677	-26.0	180	
P413	Extraction	1100169	494634	-15.0	180	
P420	Extraction	1099887	494918	-5.0	180	
P421	Extraction	1099701	494967	-28.0	180	
P422	Extraction	1099595	495046	-15.6	180	
P426	Extraction	1099768	495334	-13.0	180	
P380	Extraction	1099462	495260	-25.0	180	
I504P	Extraction	1099843	495565	-20.0	180	
I539P	Extraction	1100418	494840	-10.4	180	
I598P	Extraction	1100031	494962	-10.4	180	
I599P	Extraction	1099927	495087	-22.0	180	
I544P	Extraction	1100113	494817	-18.5	180	

Table 5. Phase V Restoration Simulation Results

MU4 (West Half) Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Period of Operation (days)	Comments
I612	Injection	1097753	495600	27.0	120	
I616	Injection	1098214	495400	28.0	120	
I665	Injection	1098210	495230	20.0	120	
I631	Injection	1098226	495074	12.9	120	
I644	Injection	1098362	495129	10.4	120	
I650	Injection	1097855	495570	12.9	120	
I651	Injection	1098759	494930	10.4	120	
I550	Injection	1098680	494972	12.9	120	
I658	Injection	1097709	495452	8.0	120	
I549	Injection	1097772	495327	12.9	120	
I654	Injection	1097864	495269	12.9	120	
I628	Injection	1097876	495136	11.0	120	
I672A	Injection	1097891	494970	10.4	120	
I671A	Injection	1098030	494955	12.9	120	
I668	Injection	1098085	494777	15.6	120	
I664	Injection	1098157	494691	12.9	120	
I663	Injection	1098247	494736	22.5	120	
I660	Injection	1098325	494812	22.5	120	
I620	Injection	1098350	494935	18.0	120	
I618	Injection	1098663	494914	18.0	120	
I621	Injection	1098476	495225	24.0	120	
I656	Injection	1098176	494810	12.0	120	
P430	Injection	1098928	494833	22.5	120	
P429	Injection	1097954	495551	22.0	120	
P431	Extraction	1098148	495421	-15.6	120	
P437	Extraction	1097886	495477	-31.0	120	
P446	Extraction	1098119	495169	-33.0	120	
P454	Extraction	1098247	494809	-14.5	120	
P461	Extraction	1098903	494784	-30.0	120	
I617P	Extraction	1098853	494714	-11.0	120	
I635P	Extraction	1098592	495213	-10.0	120	
I636P	Extraction	1098338	495214	-18.2	120	
I634P	Extraction	1098524	495334	-37.0	120	
P458	Extraction	1098433	495359	-27.0	120	
I624P	Extraction	1098356	495428	-29.0	120	
P463	Extraction	1098010	495101	-28.0	120	
P462	Extraction	1098253	495438	-36.0	120	
P445	Extraction	1098055	495492	-13.0	120	
I613P	Extraction	1097690	495636	-7.0	120	
I653P	Extraction	1098241	494941	-12.0	120	
P393	Extraction	1097954	495551	-32.0	120	
P394	Extraction	1098597	495058	-15.6	120	

Table 6. Phase VI Restoration Results

MU5 (Eastern Portion) Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Period of Operation (days)	Comments
I1175	Injection	1098120	498240	9.0	180	
I1186	Injection	1097949	497813	14.0	180	
I1202	Injection	1097966	498182	13.0	180	
I676	Injection	1098514	496924	2.0	180	
P683I	Injection	1098553	497688	20.0	180	
I719	Injection	1097839	497636	10.0	180	
I727	Injection	1098782	497322	10.0	180	
I728	Injection	1098755	497094	5.0	180	
I761	Injection	1098162	497194	36.0	180	
I775	Injection	1098184	497811	20.0	180	
P790I	Injection	1098400	497354	10.0	180	
I802	Injection	1098223	496835	6.7	180	
P814I	Injection	1098119	497929	20.0	180	
P718I	Injection	1098852	497060	5.0	180	
I723	Injection	1098896	496843	5.0	180	
I730	Injection	1098468	496575	3.6	180	
I744	Injection	1098900	496628	5.0	180	
P706I	Injection	1098949	496955	15.0	180	
I742	Injection	1098623	497368	21.0	180	
P748I	Injection	1098076	497421	10.0	180	
P749I	Injection	1098168	498097	5.0	180	
I754	Injection	1098353	497091	10.0	180	
I774	Injection	1098446	496804	2.0	180	
P846I	Injection	1098013	497711	10.0	180	
P690	Extraction	1098119	497773	-31.0	180	
P691	Extraction	1097891	497717	-5.0	180	
P745	Extraction	1098838	496743	-10.0	180	
P767	Extraction	1098311	497996	-20.0	180	
P770	Extraction	1098514	496765	-3.0	180	
P773	Extraction	1098365	496668	-6.0	180	
I860P	Extraction	1097981	497553	-26.0	180	
I1168P	Extraction	1097950	497971	-35.0	180	
I1173P	Extraction	1098006	498329	-10.0	180	
I721P	Extraction	1098506	497484	-25.0	180	
795P	Extraction	1098278	497461	-20.0	180	
712P	Extraction	1098567	497194	-34.0	180	
I736P	Extraction	1098473	497126	-11.0	180	
P741	Extraction	1098692	496980	-36.0	180	

Table 7. Phase VII Restoration Simulation Results

MU5 (Western Portion) Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Period of Operation (days)	Comments
I698	Injection	1096783	497374	18.2	120	
P1002I	Injection	1096412	497685	15.6	120	
1003I	Injection	1095916	497102	15.6	120	
I1010	Injection	1095983	497385	18.2	120	
I1011	Injection	1096178	497367	15.6	120	
I1012	Injection	1096379	497436	10.0	120	
I1021	Injection	1096282	497283	15.6	120	
P1028I	Injection	1096252	497338	5.0	120	
I1040	Injection	1096283	497025	15.6	120	
I1046	Injection	1096276	497545	10.0	120	
P1050I	Injection	1096548	497209	18.5	120	
P1055I	Injection	1096545	496957	20.8	120	
P1062I	Injection	1096374	497365	7.0	120	
P1064I	Injection	1096765	497212	15.0	120	
P1076I	Injection	1096774	496829	10.4	120	
I1078	Injection	1096968	497164	9.0	120	
I1080	Injection	1097170	497065	22.0	120	
I1088	Injection	1096975	496790	10.0	120	
P1094I	Injection	1096433	497016	21.8	120	
I1103	Injection	1097030	496644	27.0	120	
I1130	Injection	1097299	496584	9.0	120	
I1136	Injection	1097218	496495	15.6	120	
I1142	Injection	1097502	496674	19.2	120	
P699	Extraction	1096379	497517	-10.4	120	
P998	Extraction	1096843	497086	-18.2	120	
P1013	Extraction	1096543	497083	-39.0	120	
P1016	Extraction	1096529	497493	-6.2	120	
P1020	Extraction	1096109	497326	-16.0	120	
I1038P	Extraction	1096116	497137	-20.8	120	
P1044	Extraction	1096116	497412	-16.0	120	
I1049P	Extraction	1096357	497155	-20.8	120	
I1053P	Extraction	1096727	497023	-26.0	120	
I1066P	Extraction	1096910	497284	-2.0	120	
P1085	Extraction	1096992	496958	-40.0	120	
P1094	Extraction	1097063	496837	-38.3	120	
I1097P	Extraction	1097212	496825	-16.0	120	
P1073	Extraction	1096878	497020	-22.0	120	
P1104P	Extraction	1097214	496668	-27.0	120	
P1116	Extraction	1097678	496536	-21.8	120	
P1137	Extraction	1097352	496814	-10.0	120	

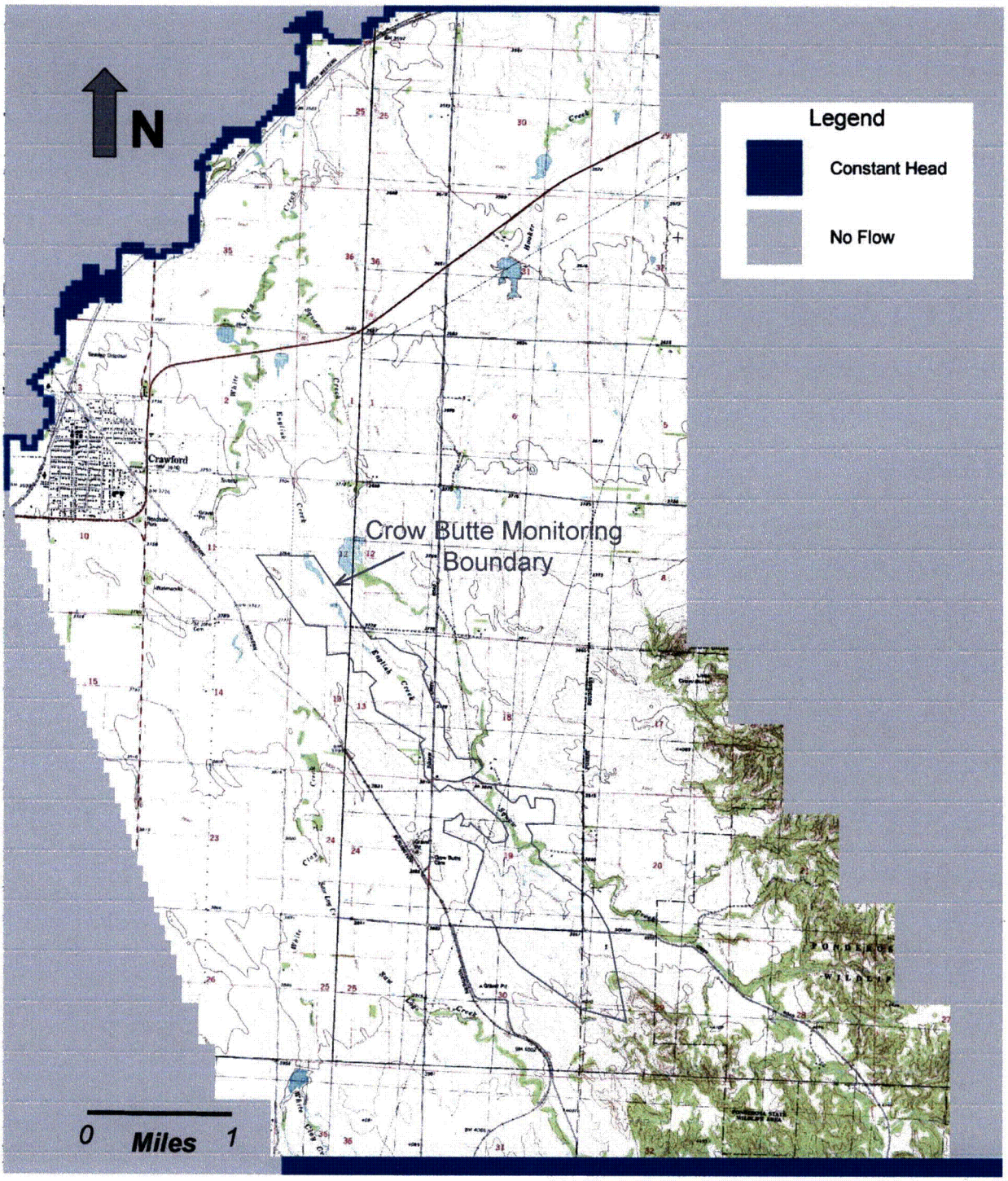
Table 8. Phase VIII Restoration Simulation Results

MU5 (Northern Portion) Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Period of Operation (days)	Comments
I1147	Injection	1098585	497933	15.6	180	
P1189I	Injection	1096834	499022	10.4	180	
P1253I	Injection	1097402	498676	5.2	180	
P821I	Injection	1099452	497805	5.0	180	
I852	Injection	1097797	498442	10.0	180	
P873I	Injection	1099790	497393	17.8	180	
I913	Injection	1099510	497490	6.2	180	
I933	Injection	1099090	497768	5.0	180	
I954	Injection	1098946	497632	13.0	180	
I962	Injection	1099011	497765	7.8	180	
I1245	Injection	1097064	498443	1.0	180	
I796	Injection	1098738	498284	5.0	180	
I797	Injection	1096930	498461	4.2	180	
I1218	Injection	1096835	498636	6.0	180	
P1213I	Injection	1096756	498629	6.0	180	
I1191	Injection	1096681	498626	6.0	180	
P1181I	Injection	1098399	498119	3.0	180	
P1196I	Injection	1096572	498748	6.0	180	
I1190	Injection	1096612	498908	2.0	180	
I1223	Injection	1096774	498989	4.2	180	
P1208I	Injection	1096856	498875	6.0	180	
P1247I	Injection	1096872	498718	6.0	180	
I1224	Injection	1097224	498614	2.0	180	
P1144I	Injection	1098779	498002	18.2	180	
I1139	Injection	1098876	497897	8.9	180	
I817	Injection	1099516	497985	10.0	180	
P843I	Injection	1099769	498052	8.9	180	
I858	Injection	1099747	498136	5.2	180	
I863	Injection	1097573	498567	5.0	180	
I877	Injection	1099511	498141	5.0	180	
P884I	Injection	1099798	497881	8.0	180	
P889I	Injection	1099691	497935	8.9	180	
P874I	Injection	1099730	497754	5.2	180	
I898	Injection	1099635	497427	5.0	180	
I899	Injection	1099656	497621	7.8	180	
I905	Injection	1099514	497627	8.9	180	
P804I	Injection	1099546	498202	5.0	180	
I806	Injection	1099548	497705	4.0	180	
I909	Injection	1099171	497640	13.0	180	
I917	Injection	1099121	497381	10.0	180	
P930I	Injection	1089898	497568	10.0	180	
I941	Injection	1099035	497506	7.8	180	

MU5 (Northern Portion) Wells and Rates

Well ID	Well Type	Easting (ft)	Northing (ft)	Rate (gpm)	Period of Operation (days)	Comments
I946	Injection	1099222	497827	5.0	180	
I1112	Injection	1098861	497758	15.0	180	
P1149I	Injection	1098751	497701	15.0	180	
I1197	Injection	1097349	498734	1.0	180	
P1203I	Injection	1097533	498723	5.0	180	
I1255	Injection	1097162	498519	4.2	180	
P1254	Extraction	1097522	498629	-26.0	180	
P1259	Extraction	1096726	498822	-21.0	180	
P686	Extraction	1099633	498063	-20.0	180	
I688P	Extraction	1099623	497557	-18.2	180	
P690	Extraction	1097144	498627	-5.0	180	
I693P	Extraction	1097633	498524	-14.0	180	
P695	Extraction	1096786	498753	-20.0	180	
I787P	Extraction	1099596	497869	-18.0	180	
P1155	Extraction	1098709	497853	-33.8	180	
P947	Extraction	1099317	497801	-13.0	180	
I904P	Extraction	1099617	497684	-20.0	180	
I919P	Extraction	1099101	497639	-34.8	180	
I931P	Extraction	1099111	497508	-22.0	180	
P940	Extraction	1099270	498108	-18.2	180	
P962	Extraction	1099011	497764	-31.2	180	
I1127P	Extraction	1098634	498183	-15.6	180	
I1158P	Extraction	1098470	498070	-12.0	180	
P1209	Extraction	1097001	498496	-7.8	180	
P1222	Extraction	1097249	498423	-10.0	180	

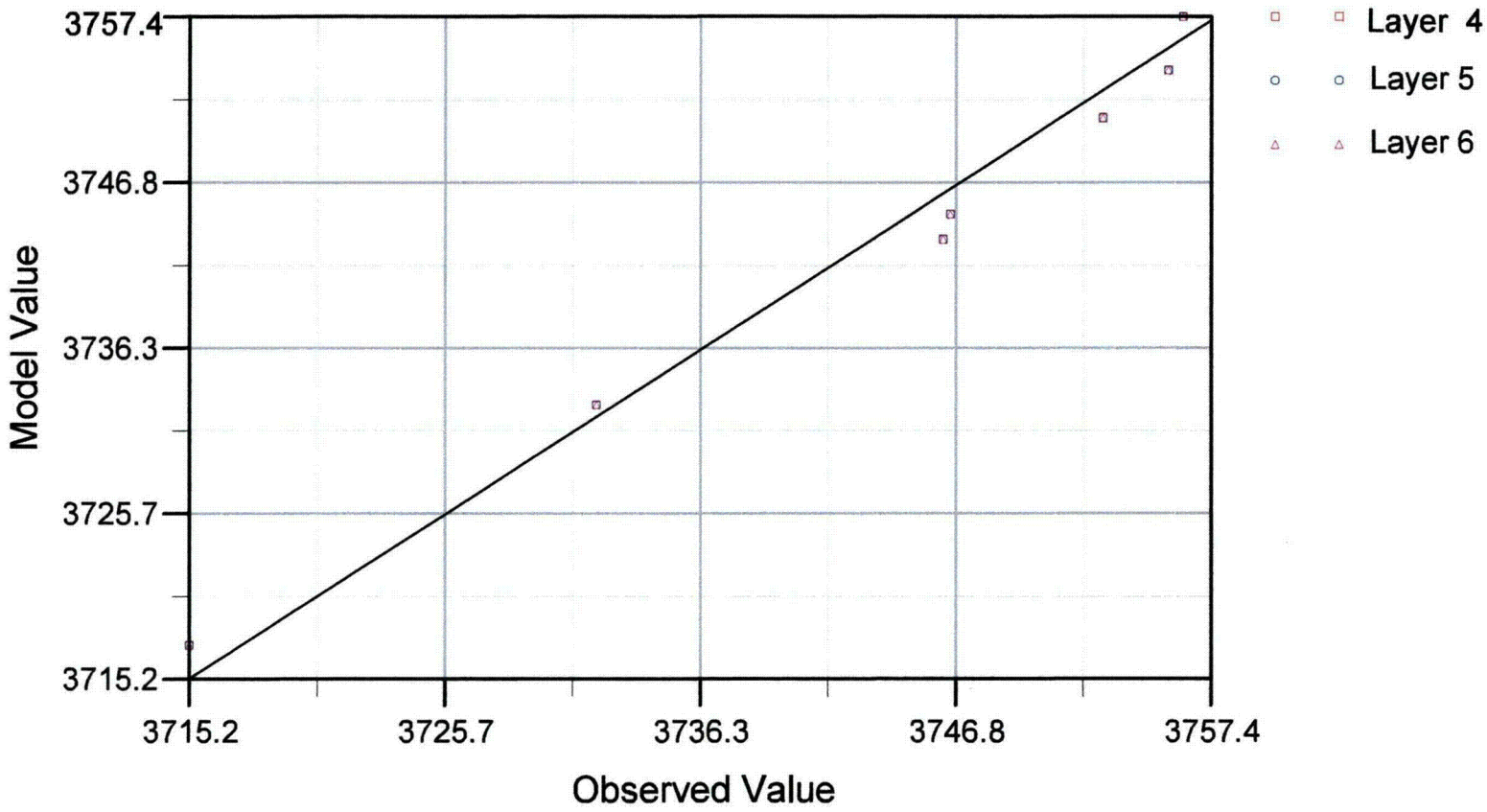


Crow Butte Resources
Wellfield Restoration Modeling

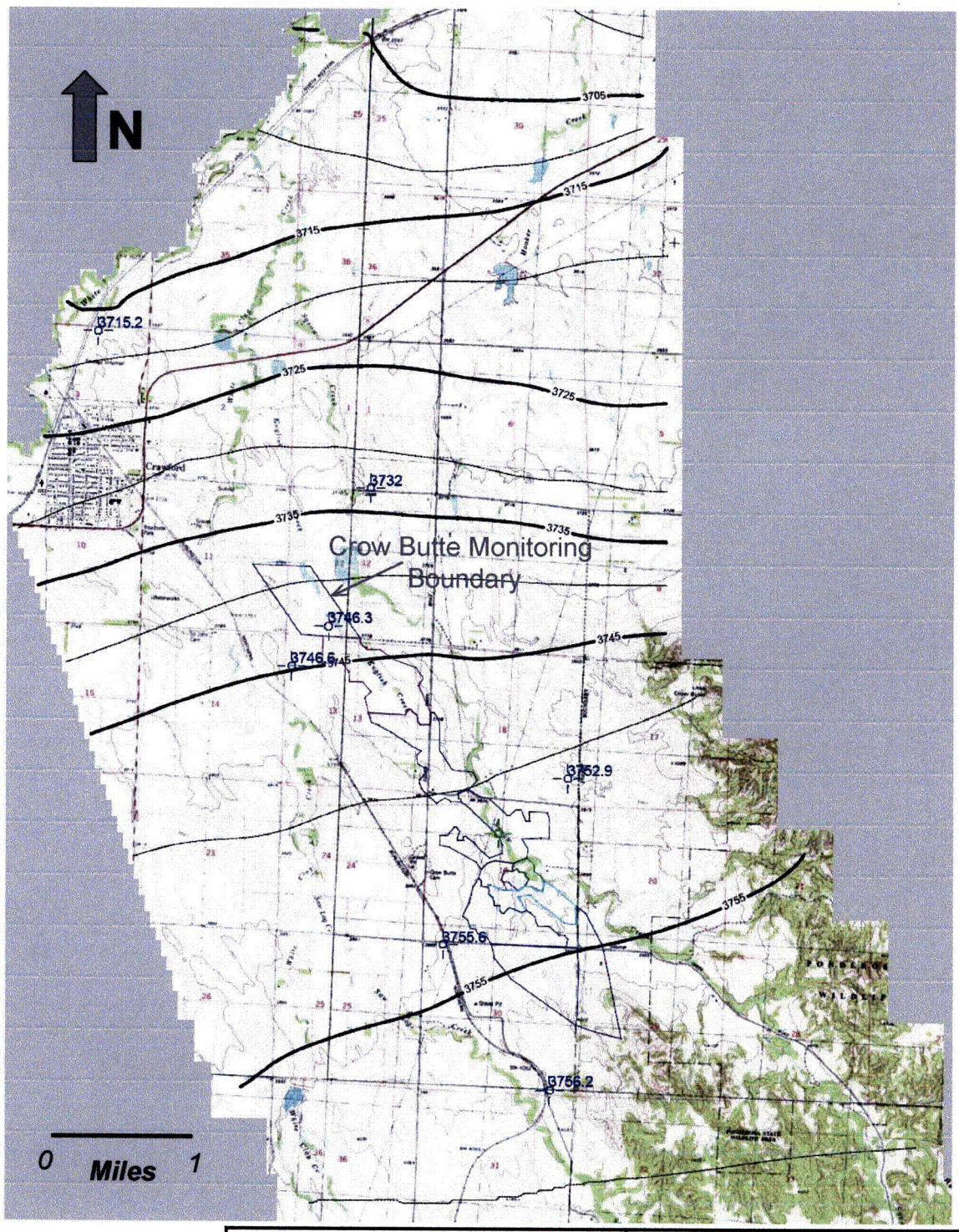
WorleyParsons
resources & energy

MODFLOW-2000 Model Domain and Boundary Conditions

Drawn By:	Edited By:	Date:
BL	BL	11/8/08
Approved By: MG		Figure 1



Crow Butte Resources **Wellfield Restoration Modeling**	**WorleyParsons** resources & energy		
Flow Model Calibration Results Observed vs. Modeled Water Levels, January 1983	DRAWN BY: BL	EDITED BY: BL	DATE: 11/8/2008
	APPROVED: MG	**Figure 2**	



Crow Butte Resources
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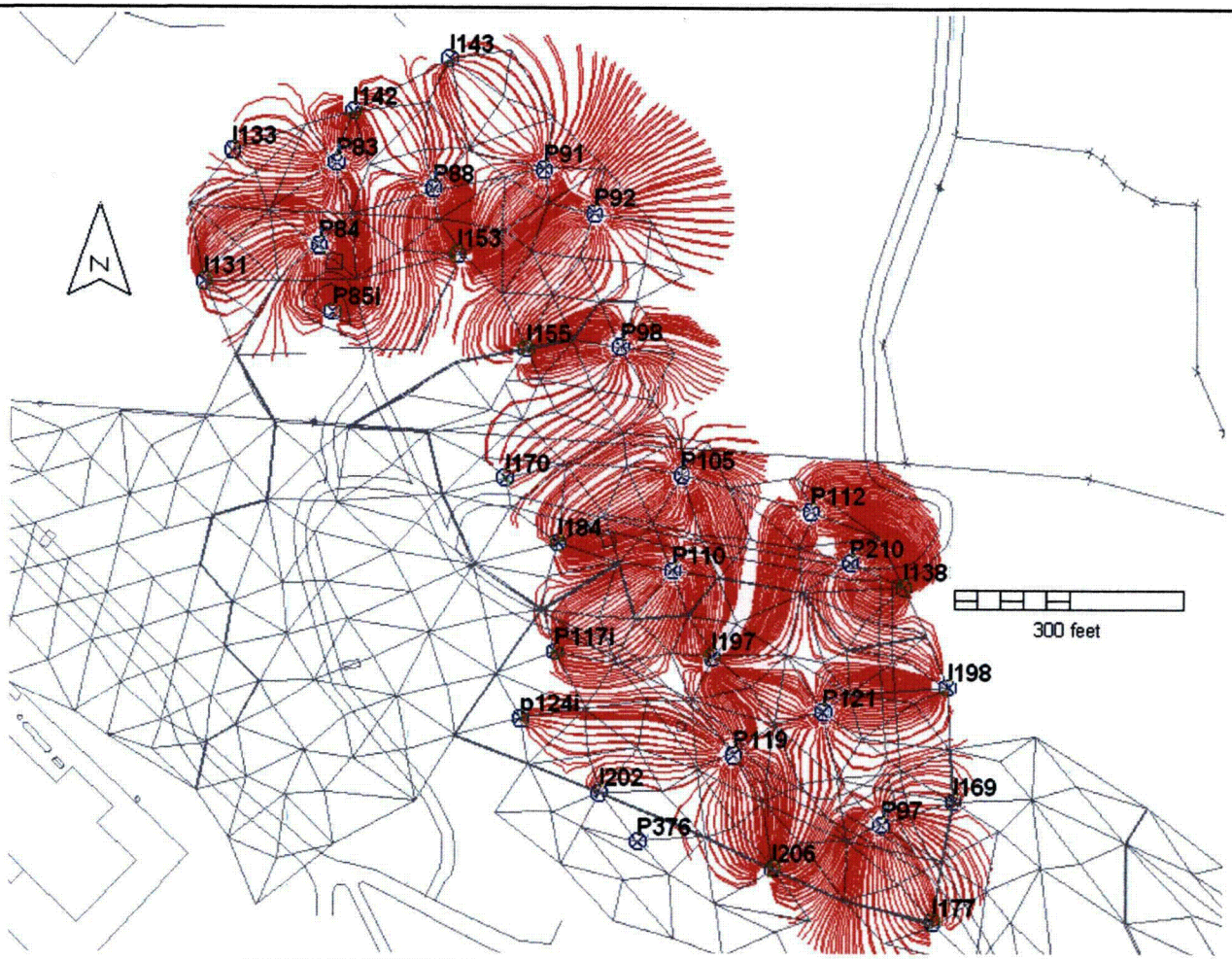
Calibrated Groundwater Elevation (ft-MSL)
Basal Chadron Sandstone
January 1983

Drawn By:	Edited By:	Date:
BL	BL	11/8/08

Approved By:	
MG	Figure 3



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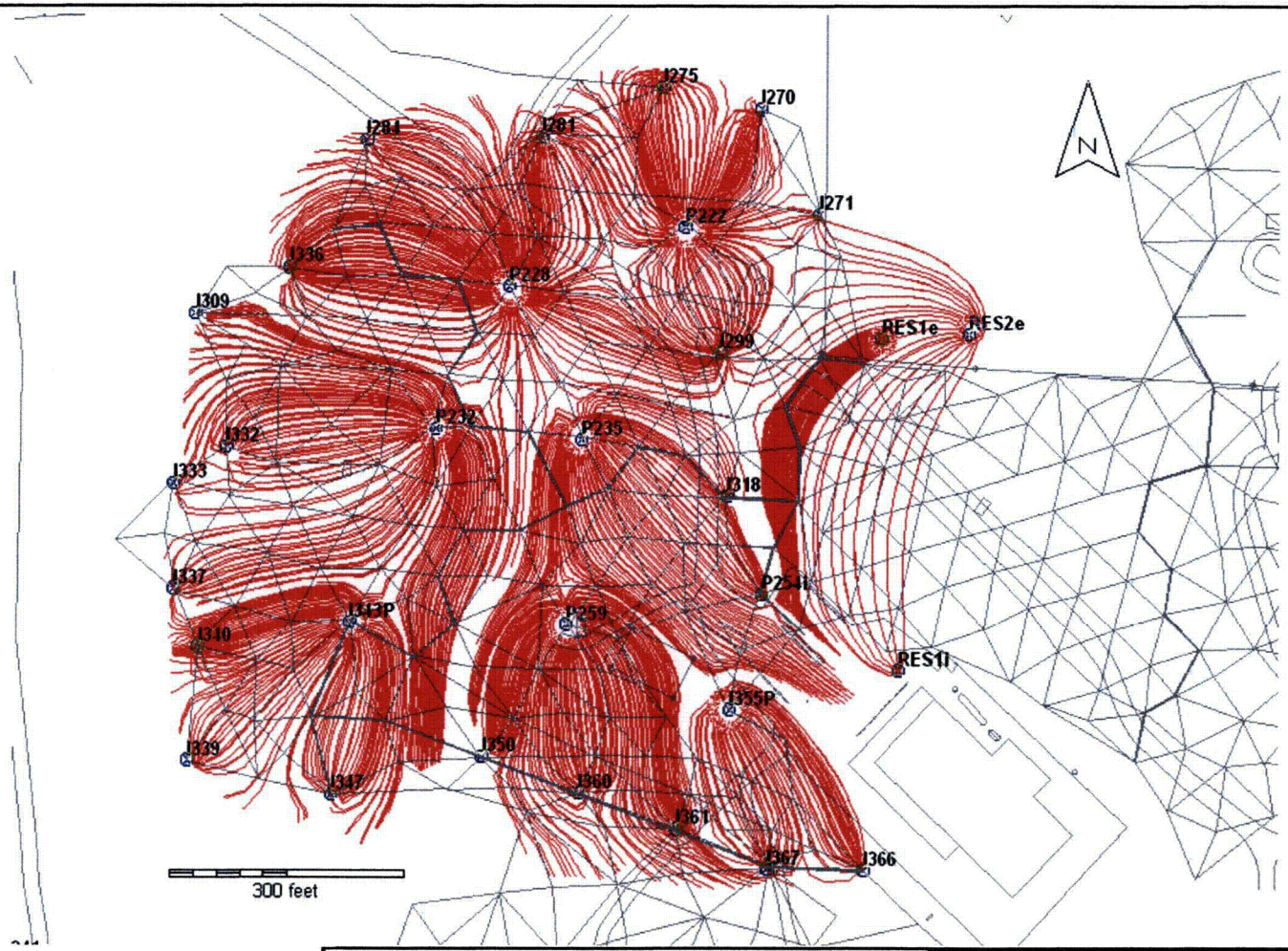
Phase I Restoration Results – MU2
Optimized Wellfield Configuration and Four Month Particle Traces
(Treatment Area)

DRAWN BY:	EDITED BY:	DATE:
BL	BL	1/20/09
APPROVED: MG		**Figure 4**



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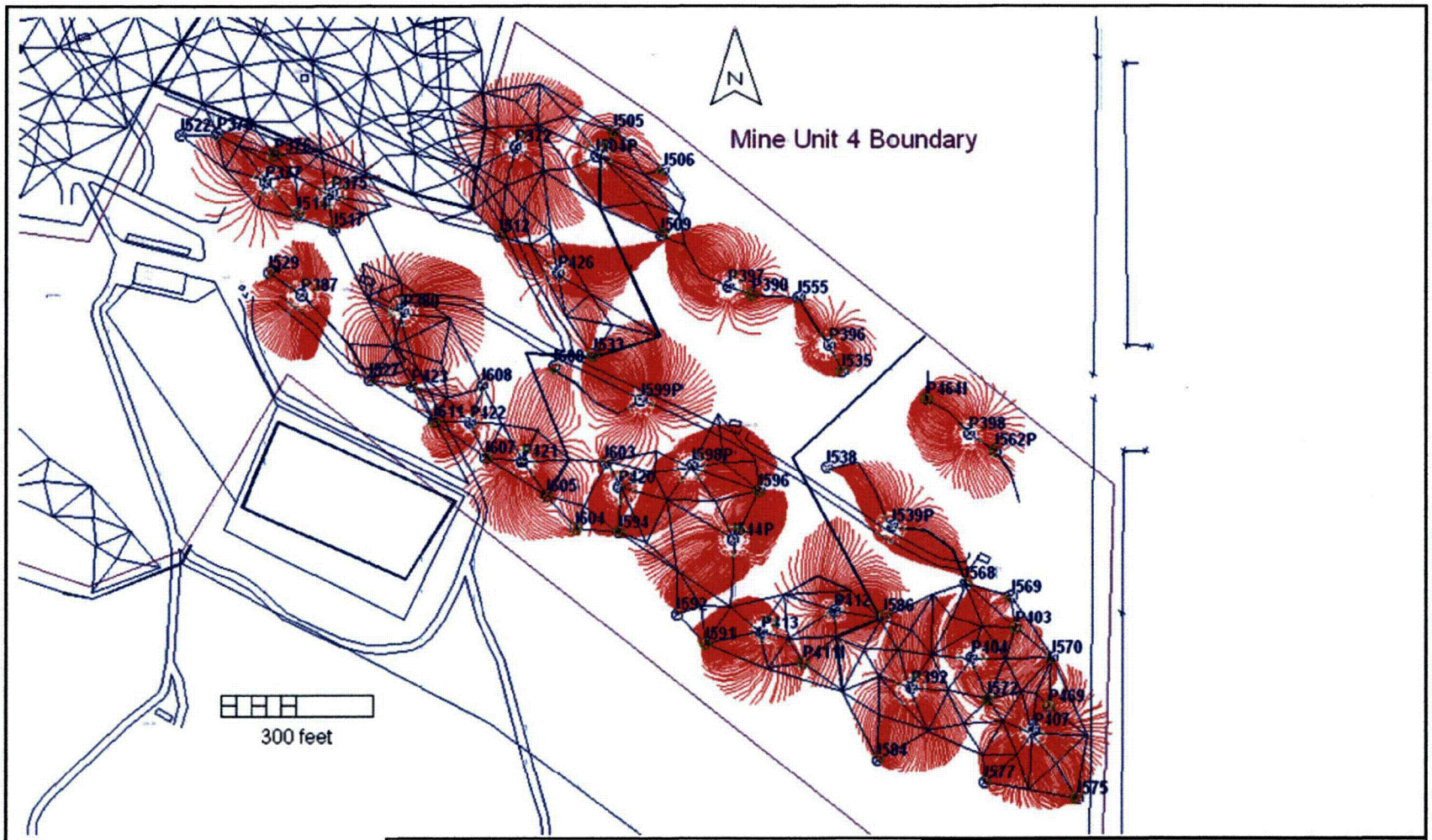
Phase II and III Restoration Results – MU3
Optimized Wellfield Configuration and Eight Month Particle Traces
(Treatment Area)

DRAWN BY:	EDITED BY:	DATE:
BL	BL	1/20/09
APPROVED: MG		**Figure 5**



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Phase IV Restoration Results – East Half MU4
Optimized Wellfield Configuration and Six Month Particle Traces
(Treatment Area)

DRAWN BY:	EDITED BY:	DATE:
BL	BL	1/20/09
APPROVED: MG		**Figure 6**

Crow Butte Resources
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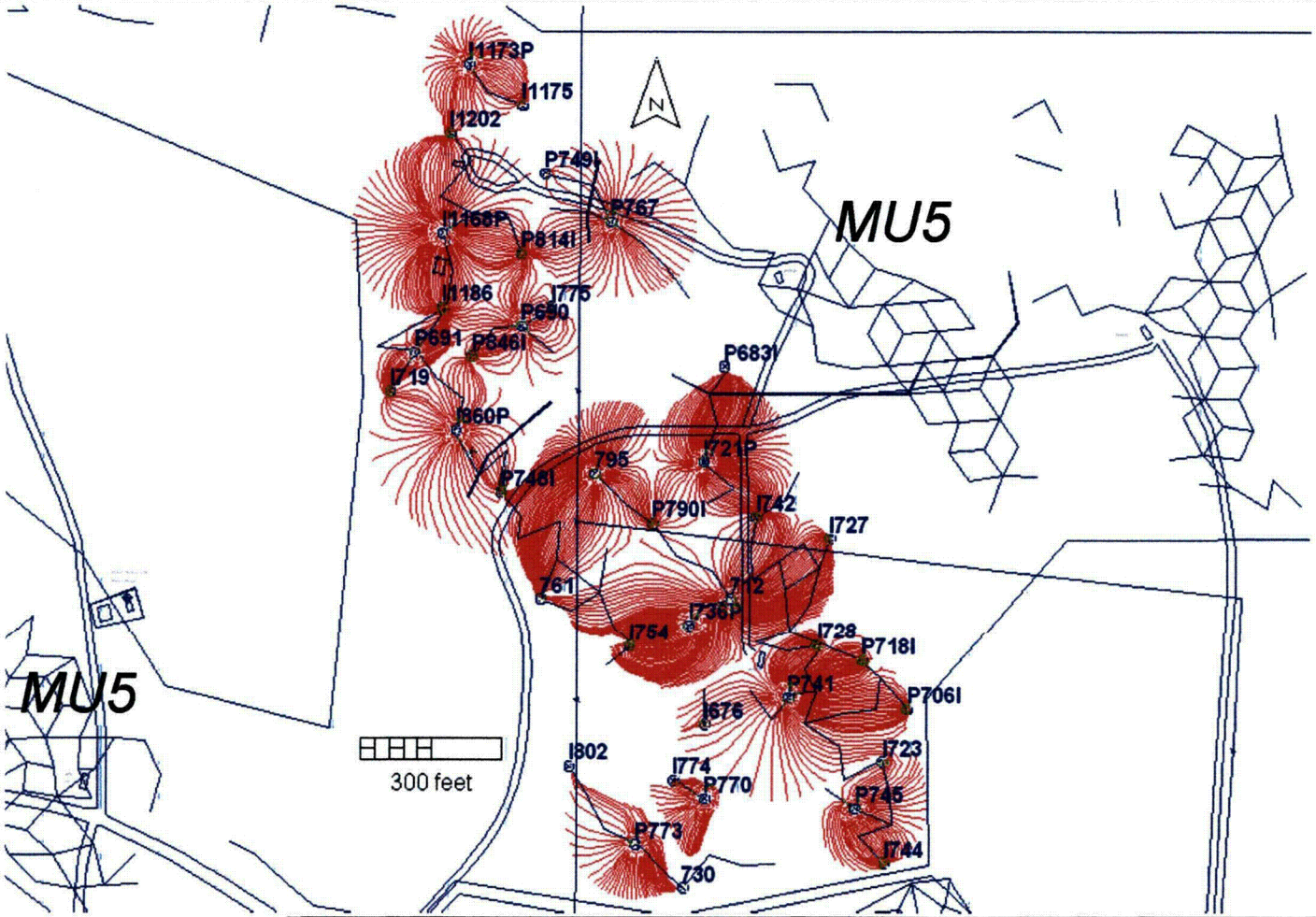
Phase V Restoration Results – West Half MU4
Optimized Wellfield Configuration and Four Month Particle Traces
(Treatment Area)

DRAWN BY:	EDITED BY:	DATE:
BL	BL	1/20/09
APPROVED: MG		**Figure 7**



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Wellfield Restoration Modeling

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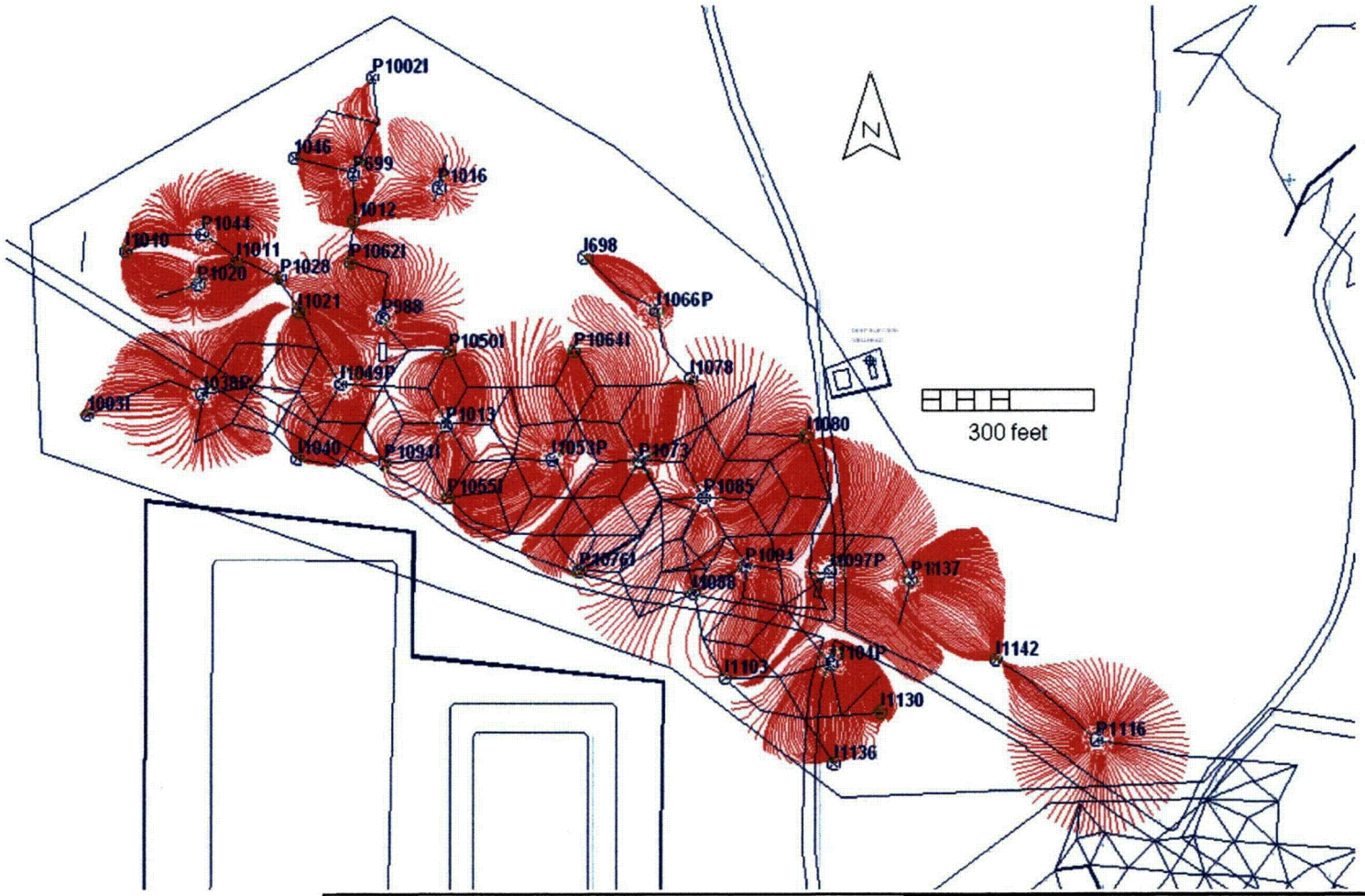
Phase VI Restoration Results – Eastern Portion of MU5
Optimized Wellfield Configuration and Six Month Particle Traces
(Treatment Area)

DRAWN BY:	EDITED BY:	DATE:
BL	BL	1/20/09
APPROVED: MG		**Figure 8**

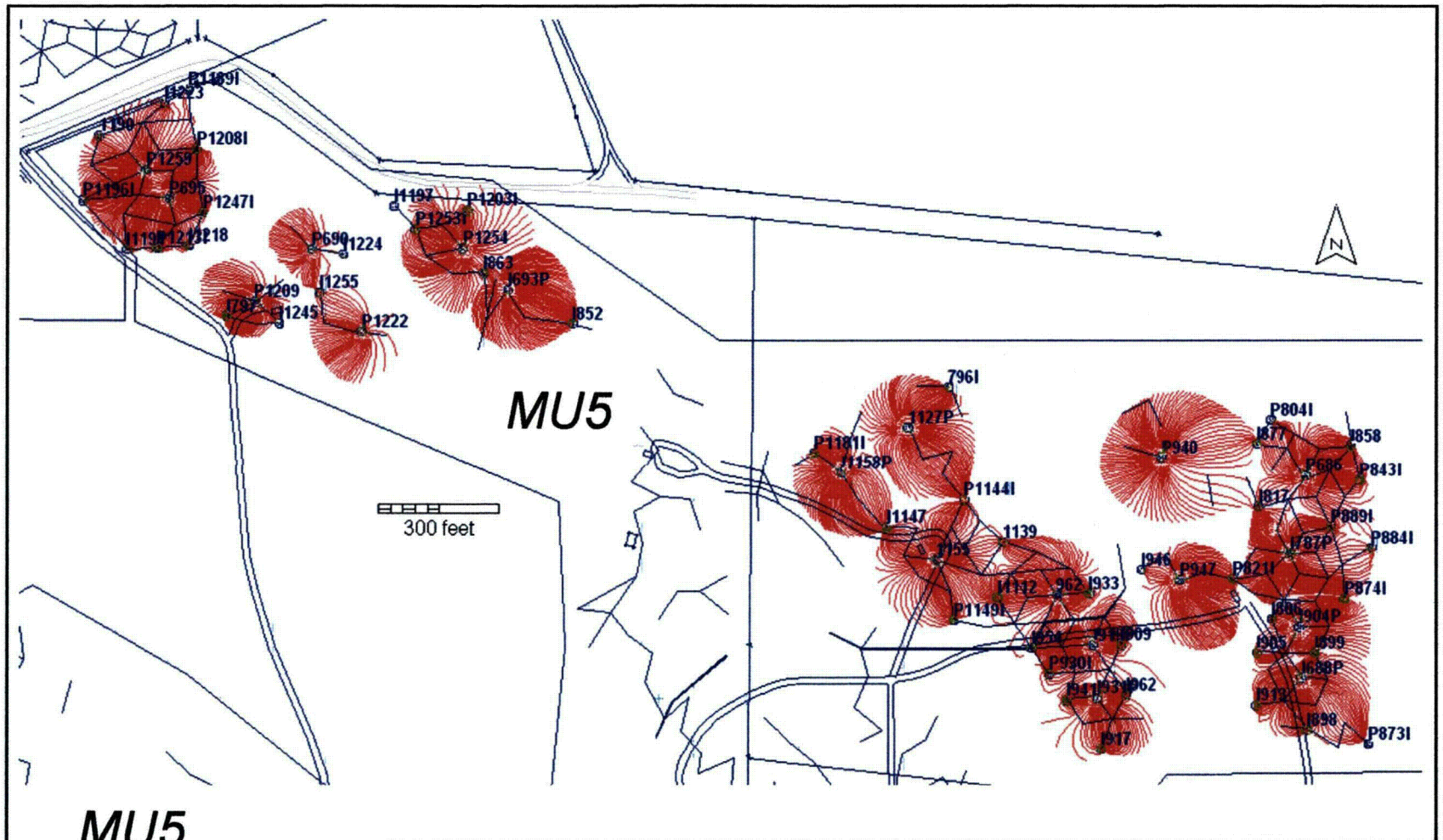


Crow Butte Resources
Wellfield Restoration Modeling

WorleyParsons
resources & energy

Phase VII Restoration Results – Western Portion of MU5
Optimized Wellfield Configuration and Four Month Particle Traces
(Treatment Area)

DRAWN BY:	EDITED BY:	DATE:
BL	BL	1/20/09
APPROVED: MG		**Figure 9**



Crow Butte Resources
Wellfield Restoration Modeling

WorleyParsons
resources & energy

Phase VIII Restoration Results – Northern Portion of MU5
Optimized Wellfield Configuration and Six Month Particle Traces
(Treatment Area)

DRAWN BY:	EDITED BY:	DATE:
BL	BL	1/20/09
APPROVED: MG		**Figure 10**

CROW BUTTE RESOURCES RESTORATION SCHEDULE

			2009				2010				2011				2012				2013				2014				2015				2016				2017				2018				2019				2020				2021				2022				2023			
			Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
MINE UNIT 2		**524 days**																																																														
IX Treatment/Reinjection	100 GPM	90 days																																																													
RO Treatment	408 GPM	184 days		6 PV																																																												
Recirculation	100 GPM	250 days				2 PV																																																										
MINE UNIT 3		**877 days**																																																													
IX Treatment/Reinjection	100 GPM	331 days		3 PV																																																												
RO Treatment	204 GPM	325 days				6 PV																																																										
Recirculation	100 GPM	221 days								2 PV																																																						
MINE UNIT 4		**1353 days**																																																													
IX Treatment/Reinjection	100 GPM	602 days				3 PV																																																										
RO Treatment	408 GPM	295 days								6 PV																																																						
Recirculation	100 GPM	402 days												2 PV																																																	
MINE UNIT 5		**2015 days**																																																													
IX Treatment/Reinjection	100 GPM	920 days				3 PV																																																										
RO Treatment	408 GPM	451 days											6 PV																																																		
Recirculation	100 GPM	613 days																2 PV																																													
MINE UNIT 6		**2232 days**																																																													
IX Treatment/Reinjection	100 GPM	1035 days							3 PV																																																							
RO Treatment	408 GPM	507 days																			6 PV																																											
Recirculation	100 GPM	690 days																							2 PV																																							
MINE UNIT 7		**2592 days**																																																													
IX Treatment/Reinjection	100 GPM	1356 days																					3 PV																																										
RO Treatment	816 GPM	332 days																													6 PV																																
Recirculation	100 GPM	904 days																																	2 PV																													
MINE UNIT 8		**1705 days**																																																													
IX Treatment/Reinjection	200 GPM	935 days																									3 PV																																				
RO Treatment	816 GPM	458 days																																			6 PV																									
Recirculation	400 GPM	312 days																																							2 PV																					
MINE UNIT 9		**1704 days**																																																													
IX Treatment/Reinjection	200 GPM	790 days																															3 PV																														
RO Treatment	816 GPM	387 days																																									6 PV																			
Recirculation	200 GPM	527 days																																													2 PV														
MINE UNIT 10		**1943 days**																																																													
IX Treatment/Reinjection	400 GPM	734 days																																					3 PV																								
RO Treatment	816 GPM	720 days																																															6 PV												
Recirculation	400 GPM	489 days																																																					2 PV						
MINE UNIT 11		**1518 days**																																																													
IX Treatment/Reinjection	400 GPM	574 days																																																						3 PV						
RO Treatment	816 GPM	562 days																																																								6 PV				
Recirculation	400 GPM	382 days																																																											2 PV	