Newmont Mining Corporation
Cripple Creek & Victor Gold Mining Company
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P.O. Box 191
Victor, CO 80860
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February 10, 2020

SENT CERTIFIED RETURN RECEIPT REQUESTED
ELECTRONIC DELIVERY

Mr. Timothy Cazier, P.E.
Environmental Protection Specialist
Colorado Department of Natural Resources
Division of Reclamation, Mining and Safety
Office of Mined Land Reclamation
1313 Sherman Street, Room 215
Denver, Colorado 80203

Re: <u>Permit No. M-1980-244; Cripple Creek & Victor Gold Mining Company; Cresson Project; – TR 120 Preliminary Adequacy Review Response – Process Fluid Injection Program Expansion</u>

Dear Mr. Cazier:

On January 30, 2020 Newmont Corporation – Cripple Creek and Victor Gold Mining Company (CC&V) received the Division of Reclamation, Mining and Safety (DRMS) preliminary adequacy review of Technical Revision (TR) 120, proposing an expansion of the process fluid injection program. Below are DRMS comments in italics followed by CC&V's responses in bold.

1) *<u>Figure 1</u>: There are 151 VLF 1 well locations identified with blue circles and 9 Hydro-Jex well locations identified with green circles. Given the total number of 160 wells, it would be very useful if some issue with one or more of these wells developed to have an identifier for each in order to determine the location of a particular well. Based on the site visit on January 28, 2020, the DRMS understands the original nine Hydro-Jex wells are identified as HJ-1 through HJ-9 from north to south. Please resubmit Figure 1 with a unique identifier on each of the 160 wells.*
Enclosed, Figures 1-5 include an identifier to determine the location of each well.
2) *<u>Well usage constraint clarification</u>: The majority of the TR-120 submittal is a resubmittal of information submitted with TR-57. There are three recommendations (reference p. 8 of the December 17, 2009 letter from Amec to Timm Comer) dealing with crest offsets; injection depths; and injection pressure and monitoring. In addition, section 4, "VLF Operational Balances" of the "Hydro-Jex Project Monitoring Program" from CC&V to the DRMS, dated March 11, 2010 suggests injection flow rates will not exceed the pumping capacity of the high volume solution collection pumps in any PSSA being treated. No numerical values are provided for any of these parameters, other than the minimum 20-foot offset from the crest (for injection depths less than 100 feet BGS), half overburden pressure limits for injections in the upper 70 feet of a well. Furthermore, injection well HJ-8 was measured to be 19 feet from the crest during the*

aforementioned site visit, thereby limiting its use to injection at depths greater than 100 feet. Site personnel also indicated the injection wells are screened over a large interval, but the injection interval is limited to a five-foot section using inflatable packers. As such, it appears there is considerable variability in the operation of these injection wells with only vague references to safe pressure and flow limits. Site personnel described how HJ-8 was injecting at a depth of 115 feet and was limited to the lesser of 1600 gpm or about 115 psi in order to meet the recommended guidelines set forth in TR-57. In order to provide clarity on the operation limitations of each of the 160 wells, please provide the following:

a. *Tabular or formulaic method to estimate overburden pressure,*
   Enclosed, Attachment 1 details the method to estimate overburden pressure.
b. *Method used to control injection interval,*
   Enclosed, Attachment 2 details the method used to control injection interval.
c. *Means of monitoring slope movement (e.g., visual monitoring, instrument monitoring) and the frequency of each,*
   Prism monitoring will continue on a weekly basis, measuring total vertical displacement via laser at the active injection sites.
d. *Trigger/minimum movement, or other criteria observed that would dictate termination of fluid injection.*
   If, during the injection program, the survey data indicates a total vertical displacement rate of 1-inch per week or greater, the injection activities should be terminated and the injection pressures revised.

And, for each well:

e. *Well depth and full screen interval (in feet bgs),*
   Enclosed, Attachment 3 details the well depth and screen interval.
f. *Depth from bottom of well to top of liner,*
   Attachment 3 details the depth from the bottom of the well to the top of liner.
g. *Well offset from bench crest,*
   As described in the Hydro-Jex Monitoring Program, approved in TR-57, "The injection wells should be located a minimum of 20 feet from the crest of any ore benches. Only the injection wells that have deep (100+ feet) injection depths can be located closer than 20 feet from the bench crest." Attachment 3 includes depth information for each well, none of which are less than 100 feet. All injection wells will be installed and operated following the established crest and depth limitations as outlined in the aforementioned monitoring program.
h. *PSSA phase to which the well contributes and PSSA phase pump capacity.*
   Attachment 3 details PSSA phases associated with each well.

3) *<u>Well construction details</u>: Please provide a typical well construction detail, or details if there are significant differences between wells, or construction logs (if available). The provided information should include perforation size and spacing, casing material and diameter.*
   Enclosed, Attachment 4 describes well construction details.

4) *<u>Monitoring reporting</u>: Please provide a monitor reporting frequency and duration to demonstrate continued safe operation of the 160 VLF 1 injection wells.*
   Geotechnical monitoring will continue on a weekly basis, as described in CC&V's response to 2c and d, above. PSSA levels will also continue to be monitored regularly, reporting any required exceedances.

5) *<u>Reclamation</u>: No reclamation is proposed for the 160 well heads. The DRMs acknowledges no reclamation was required for the nine pilot project wells approved under TR-57. The approved post mine land use is rangeland. The Hydro-Jex well head observed during the January 28, 2020*

inspection is on the order of five feet above the bench surface and measured to be 19 feet from the crest. Please describe how the continued presence of the existing 160 well heads after reclamation is consistent with the approved post mine land use.
The Hydro-Jex system is comprised of steel casings that are installed on the leach pad, these casings extend approximately six inches above the surface. The steel riser observed during the January 28th inspection is the portal portion of the injection system, which is moved to the specific Hydro-Jex casings in current use at any given time. This Hydro-Jex riser is installed into the steel casing using an annular seal, thus allowing the well to be used for injection. The steel casings will remain after active leaching, facilitating rinsing during reclamation of the leach facilities. The current financial warranty accounts for grading of the leach pads. Through the currently planned mass grading of the leach pads, the steel casings will be buried with a minimum one foot cover on the leach pad.

Additionally, as discussed with DRMS representatives via phone on February 6, 2020, each well will be covered and secured when not in use. Should you require further information please do not hesitate to contact Katie Blake at 719.689.4048 or myself at 719.689.4042 or Justin.Raglin@newmont.com.

Sincerely,

Katie Blake

Justin Raglin
Health, Safety, Security and Environment Manager
Cripple Creek & Victor Gold Mining Co

JR/kb

Ec: T. Cazier – DRMS
M. Cunningham – DRMS
E. Russell – DRMS
P. Lennberg - DRMS
B. Bowles – DRMS
J. Raglin – CC&V
J. Bills – CC&V
K. Blake – CC&V
W. Conley – CC&V

Enclosures (9)

File: S:\CrippleCreek\na.cc.admin\Environmental\New File Structure\2-Correspondence\DNR\DRMS\2020\Outgoing

Figures

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Cripple Creek and Victor Gold Mining Company

Figure 1 - Well IDs
TR 120 Prelim. Adequacy Review
Process Fluid Injection Program Expansion

Author: K. Blake	Date: 02/2020	Photo: 9/2019
0 75 150 300 450 600 Feet	1 inch = 125 feet	

File: 20200205_WellLocationID

Attachment 1

Attachment 1

In 2010, hyddoGEOPHYSICS, Incorporated (HGI) was hired to conduct testing of the overburden pressure of the injection wells on VLF 1. HGI calculated the estimated lithostatic overburden pressure (psi) by density multiplied by gravity and injection depth and likelihood of exceeding lithostatic as a binary condition of the stable bottom hole pressure greater than the 110% of the lithostatic overburden pressure. The 110% is applied ad hoc as a means to add conservatism to the model. Table 1 shows the estimated lithostatic overburden pressures as a function of depth calculated by HGI.

Table 1

Injection Depth From Surface (ft)	Estimated Lithostatic Overburden Pressure (psi)
110	86
130	103
150	120
170	138
190	157
210	175
230	194
250	214
270	234

The equation to model this relationship is:

$$L = 0.4652 \times D^{1.1097} \quad (1)$$

Where L is lithostatic overburden pressure (psi) and D is injection depth (ft). HGI developed the following formula for head loss (H_L) by comparing top and bottom hole pressures on injection tests performed in 2013:

$$H_L = D - Q^2 (2.59\text{E-}5 \times D + 0.00172) \quad (2)$$

Where D is injection depth (ft) and Q is flow rate (ft^3/min). Q is assumed to be 1,600 gal/min or 214 ft^3/min. From this it is possible to develop a relationship between the injection depth and what the maximum top hole pressure:

$$T_M = L + H_L \quad (3)$$

Where T_M is the maximum top hole pressure. Table 2 shows maximum injection pressures using this formula and Q = 214 ft^3/min.

Attachment 1

Table 2

Injection Depth From Surface (ft)	Estimated Lithostatic Overburden Pressure (psi)	Head Loss (psi)	Maximum Top Hole Pressure (psi)
110	86	-99	185
130	103	-103	206
150	120	-106	226
170	138	-110	248
190	157	-114	271
210	175	-118	293
230	194	-121	315
250	214	-125	339
270	234	-129	363

However, HGI recommend top hole injection pressures included a factor of safety and are shown in Table 3.

Table 3

Injection Depth From Surface (ft)	HGI Recommend Top Hole Pressure (psi)
110	119
130	138
150	156
170	175
190	195
210	215
230	235
250	214
270	256

The safety factor used by HGI is a linear relationship that takes approximately 88% of maximum top hole pressure shown in Table 2 and subtracts 44 psi. From Table 3, a relationship to predict top hole pressures for deeper zones is given by:

$P_R = 0.8841 \times D - 43.9391$

Where P_R is the recommended top hole injection pressure (psi) and D is the injection depth (ft).

Attachment 2

Attachment 2

The schematic in Figure 1 illustrates the basic setup required for the injection process. A straddle packer mechanism is attached to the end of the drop pipe string and positioned within the outer casing using a hoist. The drop pipe is then secured at the well head and connected to the injection pump. Solution pumped down the drop pipe passes through the upper packer and then flows into the annulus between the inner and outer casings where it is confined vertically by the inflated packers forcing it into the heap through perforations in the well bore.

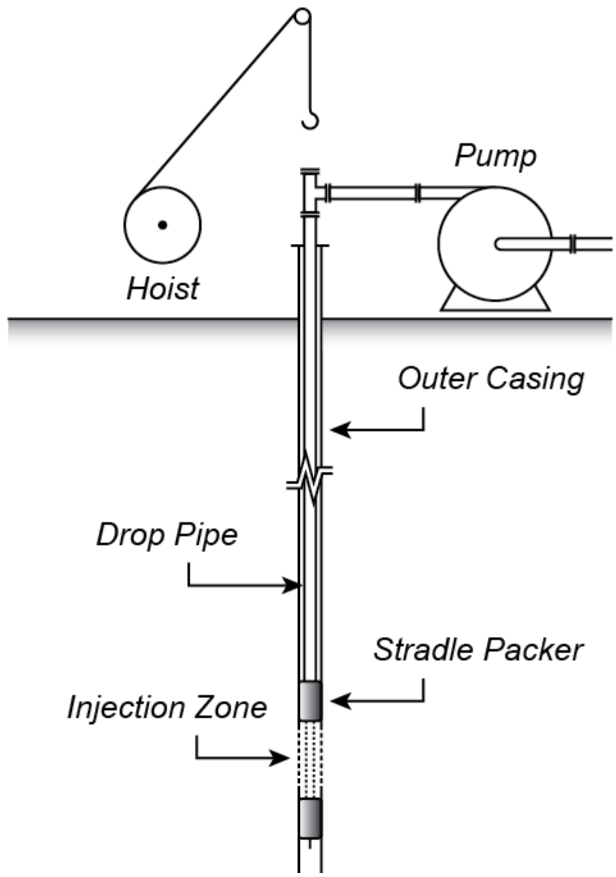

Figure 1 - Schematic diagram of the pad injection setup. In practice the straddle packer is positioned at the injection zone by raising (removing sections from) or lowering (adding sections to) the drop pipe string using the hoist. The well head is then affixed to the drop pipe string and connected to the solution pump. Solution flows through the drop pipe string and the upper packer, through a perforated pipe connecting the packers, and then is forced into the heap through perforations in the outer casing.

Figure 1 shows the pump skid plumbed to an injection well. Solution is supplied to the pump through a 6-in (15.2-cm) flexible hose connected to a barren header. The pump discharge piping on the skid features single pipe run containing two full-port ball valves and sonic flow meter to control and monitor the flow in conjunction with pressure gauges at the pump inlet and outlet. A simple bypass is also included to permit flow without assistance from the pump. A 4-in (10.2-cm) high-pressure hose connects the pump skid piping to the well head.

Figure 2 - Injection pump skid plumbed to an injection well on the VLF. Barren solution is supplied from a main distribution header on the pad and is conveyed to the pump through the flexible hose at the right. The discharge is connected to the injection head using a flexible hose.

Current packer setups have outside diameter (deflated) 5.12 inches (130 mm), and can handle set pressures of up to 900 psi when inflated to a diameter of 6 inches. Figure 14 shows the flow tube, packer setups and schematic of how they are employed at the perforated injection zone of the well. Compressed nitrogen is supplied from the surface through the 1/4 inch tubing running down the entire length of the drop pipe.

Attachment 2

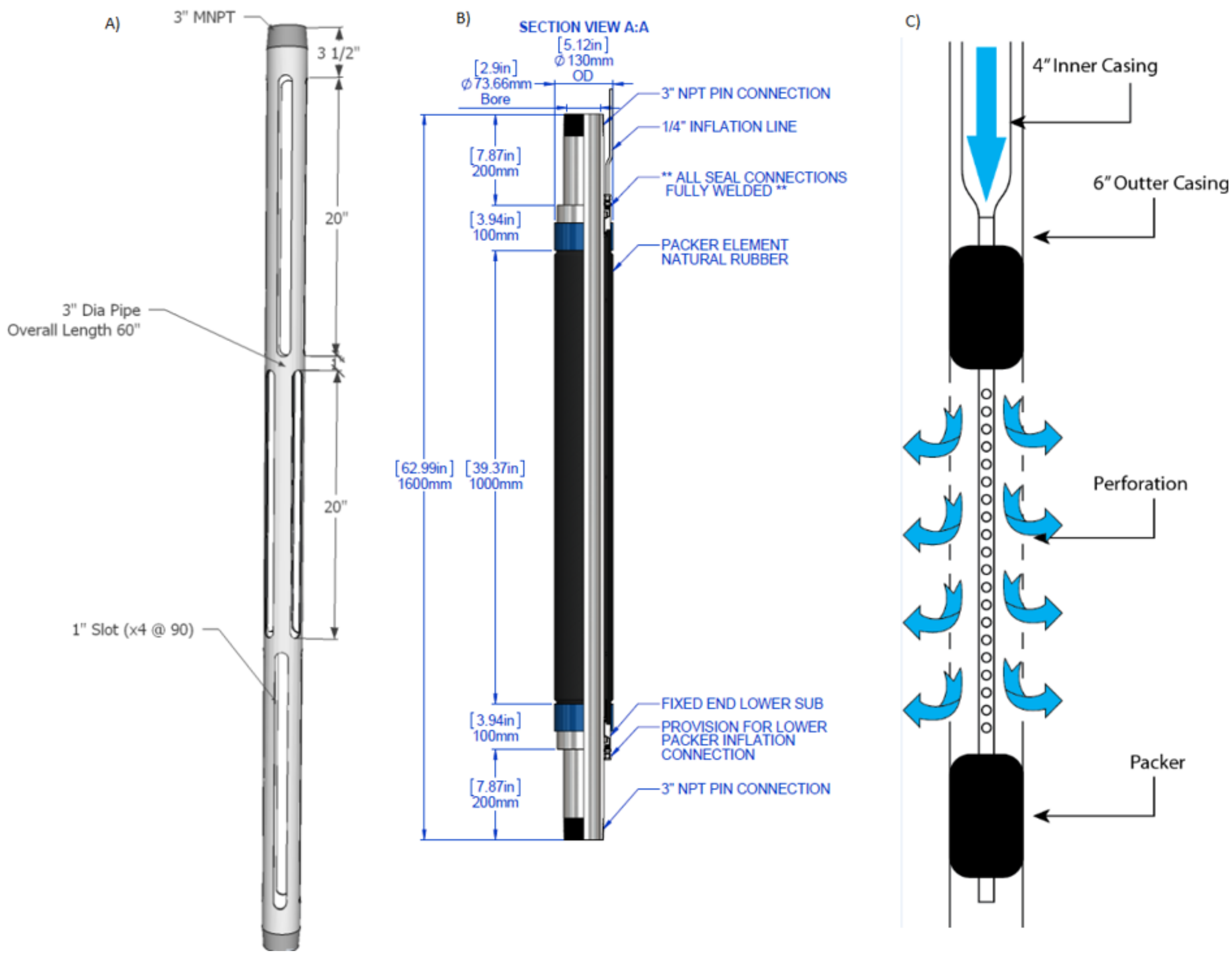

Figure 3 - Packer setups used at CC&V. A) a 5 foot section of flow tube. Two 5 foot flow tubes are screwed together to make a 10 foot flow tube to accommodate both the 5 foot perforated zones used on wells drilled prior to 2012 and the 10 foot perforated zones used on wells drilled at later dates. B) the IPI inflatable packers currently used at CC&V. One packer is screwed to the top of the two 5-foot flow tube sections and the other to the bottom section of the two 5-foot flow tubes. C) schematic showing how the packers and flow tubes are arranged to injection solution through the perforations on a well injection zone. The lower end of the bottom packer is capped to force solution laterally through the flow tubes and into the perforated injection zones of the wells.

CC&V uses a well-service truck commonly used in the water well industry. The truck has a collapsible mast that is easily positioned directly over the target injection well and a hydraulic winch that can hoist 7,000 lbs (3,175 kg) when the cable is strung in a double line configuration; the capacity is suitable for wells up to 550 ft (168 m) deep. Photographs in Figure 4 show the truck in use as well as close-ups of the winch controls and the onboard compressed cylinders used to inflate the packers.

Figure 4 - CC&V Well-service truck. a-b) Pulling a 10-ft (3-m) section of drop pipe. c) Hoist controls at the rear of the truck. d) Compressed air bottles used to inflate the packer setups.

Attachment 3

ID Number	Phase Drainage	Depth to Liner	Installed Depth	Depth above Liner	Injection Zones	Bottom Injection Zone Minimum Depth above Liner
HJ-1	2	523	420	103	17	113
HJ-2	2	537	440	97	18	107
HJ-3	2	547	440	107	18	117
HJ-4	2	563	460	103	19	113
HJ-5	2	578	460	118	19	128
HJ-6	2	584	480	104	20	114
HJ-7	2	593	480	113	20	123
HJ-8	2	553	440	113	18	123
HJ-9	2	497	380	117	15	127
BH-108	2	356	260	96	9	106
BH-109	2	385	280	105	10	115
BH-110	2	415	320	95	12	105
BH-111	2	408	300	108	11	118
BH-112	2	378	280	98	10	108
BH-113	2	346	240	106	8	116
BH-114	2	323	220	103	7	113
BH-115	2	302	200	102	6	112
BH-116	2	295	200	95	6	105
BH-117	2	285	180	105	5	115
BH-118	2	271	180	91	5	101
BH-119	2	263	160	103	4	113
BH-120	2	270	180	90	5	100
BH-121	2	281	180	101	5	111
BH-122	2	281	180	101	5	111
BH-101	2	360	260	100	9	110
BH-102	2	336	240	96	8	106
BH-103	2	302	200	102	6	112
BH-104	2	264	160	104	4	114
BH-105	2	241	140	101	3	111
BH-106	2	233	140	93	3	103
BH-107	2	215	120	95	2	105
BH-201	1	422	320	102	12	112
BH-202	1	413	320	93	12	103
BH-203	1	394	300	94	11	104
BH-204	1	364	260	104	9	114
BH-205	1	341	240	101	8	111
BH-206	1	320	220	100	7	110
BH-207	1	295	200	95	6	105
BH-208	1	270	160	110	4	120
BH-209	1	245	140	105	3	115
BH-210	1	221	120	101	2	111
BH-211	1	384	280	104	10	114
BH-212	1	378	280	98	10	108
BH-213	1	375	280	95	10	105
BH-214	1	358	260	98	9	108
BH-215	1	346	240	106	8	116
BH-216	1	339	240	99	8	109

BH-217	1	316	220	96	7	106
BH-218	1	288	180	108	5	118
BH-219	1	263	160	103	4	113
BH-220	1	242	140	102	3	112
BH-221	1	223	120	103	2	113
BH-222	1	482	380	102	15	112
BH-223	1	501	400	101	16	111
BH-224	1	518	420	98	17	108
BH-225	1	517	420	97	17	107
BH-226	1	515	420	95	17	105
BH-227	1	534	440	94	18	104
BH-228	1	551	460	91	19	101
BH-229	1	554	460	94	19	104
BH-230	1	559	460	99	19	109
BH-231	1	558	460	98	19	108
BH-232	1	549	440	109	18	119
BH-233	1	531	440	91	18	101
BH-234	1	501	400	101	16	111
BH-235	1	481	380	101	15	111
800	4	220	120	100	2	110
801	4	262	160	102	4	112
802	4	282	180	102	5	112
803	4	295	200	95	6	105
804	4	339	240	99	8	109
805	4	378	280	98	10	108
806	4	403	300	103	11	113
807	4	407	300	107	11	117
808	4	410	300	110	11	120
809	4	407	300	107	11	117
810	4	364	260	104	9	114
811	2	488	380	108	15	118
812	2	500	400	100	16	110
813	2	510	400	110	16	120
814	2	497	400	97	16	107
815	2	462	360	102	14	112
816	2	442	340	102	13	112
817	2	427	320	107	12	117
818	2	397	300	97	11	107
819	2	365	260	105	9	115
820	1	332	240	92	8	102
326	1	220	120	100	2	110
327	1	238	140	98	3	108
328	1	265	160	105	4	115
329	1	285	180	105	5	115
330	1	285	180	105	5	115
331	1	298	200	98	6	108
332	1	319	220	99	7	109
333	1	336	240	96	8	106
334	1	343	240	103	8	113
335	1	348	240	108	8	118

336	1	341	240	101	8	111
337	1	320	220	100	7	110
338	1	332	240	92	8	102
339	1	345	240	105	8	115
340	1	323	220	103	7	113
901	4	370	280	90	10	100
902	4	390	300	90	11	100
903	4	390	300	90	11	100
904	4	370	280	90	10	100
905	2	380	280	100	10	110
906	2	500	400	100	16	110
907	2	525	420	105	17	115
908	2	545	440	105	18	115
909	2	555	460	95	19	105
910	2	570	480	90	20	100
911	2	590	500	90	21	100
912	2	605	500	105	21	115
913	2	620	520	100	22	110
914	2	640	540	100	23	110
915	2	650	560	90	24	100
916	2	660	560	100	24	110
917	2	665	560	105	24	115
918	2	665	560	105	24	115
919	2	655	560	95	24	105
920	2	605	500	105	21	115
921	2	565	460	105	19	115
922	1	540	440	100	18	110
923	1	555	460	95	19	105
924	1	575	480	95	20	105
925	1	580	480	100	20	110
926	1	590	500	90	21	100

Attachment 4

Attachment 4

Typical injection well installation on VLF 1 is shown in Figure 1

- Well spacing minimum 120 feet apart.
- A 100-foot buffer is maintained from the lowest injection zone to the bottom of the pad liner.
- A standard eight-row pattern is used for all perforations; although HJ-1 through HJ-9 had truncated perforations directed only to the center of the pad in zones 70 feet or shallower.
- The length of the perforated zones is 10 ft; although HJ-1 through HJ-9 had perforation zones of 5 ft in length.
- Injections will not be performed on zones less than 100 feet in depth from the surface.

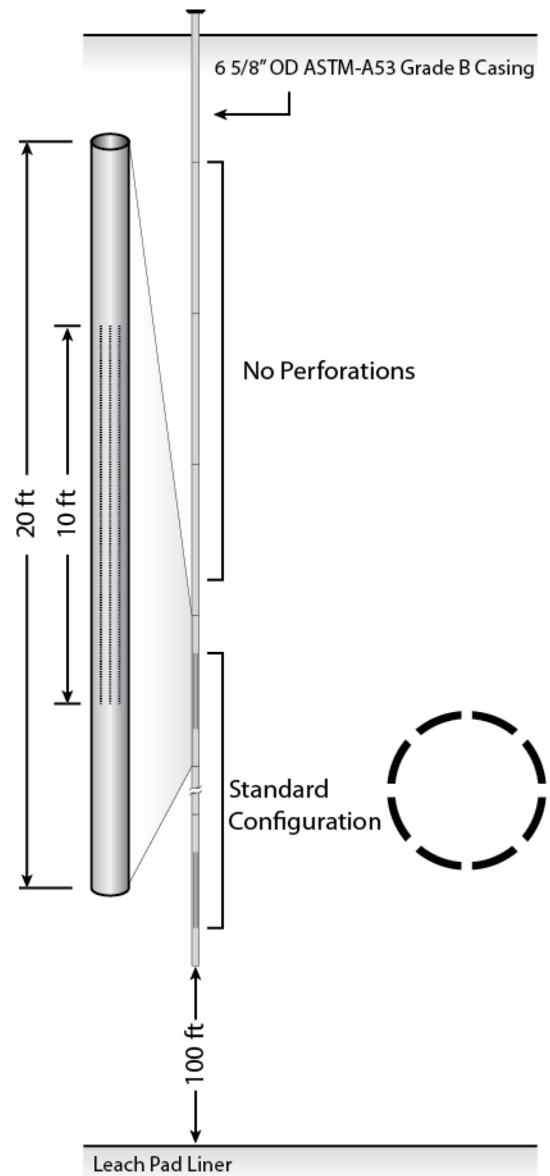

Figure 1 - Schematic of injection wells installed after 2010. The 30-, 50, and 70- ft zones were not perforated as in 2010. The standard ring pattern at right was used for all injection zones. (Not to scale.)