PIPELINE SAFETY RECORDS INSPECTION CHECKLIST

South Dakota Public Utilities Commission

I. GENERAL INFORMATION			
Operator Evaluated			
Operator ID			
Unit Description			
Portions of Unit Inspected	**Records:** Pipe-to-Soil Reads Casing Reads Isolated Segment Reads Rectifier Reads Examination of Buried Pipe Reports Interference Bond Records Gas Composition Atmospheric Corrosion Records Class Location Studies Odorization Checks Patrolling Leak Survey Line Markers Valve Maintenance		
Contact Person / Title (person interviewed)		**Email**	
Responsible Party/Title		**Email**	
Mailing Address			
Inspection Date		**Last Inspection Date**	
Location of Inspection			
Inspector Name			

II. PART 192 – CUSTOMER NOTIFICATION		S	N/I	U	N/A
§192.16	Has the operator notified all customers by **August 14, 1996** or new customers within **90** days of their responsibility for those sections of service lines not maintained by the operator?				
§192.16 (b)	Does the operator have a current copy of the notification?				
	Have all customer received the notification within the last 3 years?				
	Does notification contain all the following requirements:				
	(1) operator does not maintain the customer's buried piping				

II. PART 192 – CUSTOMER NOTIFICATION		S	N/I	U	N/A
	(2) if customer's buried piping is not maintained, it may be subject to corrosion and leakage				
	(3) buried gas piping should be: (i) periodically inspected for leaks				
	(ii) periodically inspected for corrosion (if metal pipe)				
	(iii) repaired if any unsafe condition is discovered				
	(4) when excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand				
	(5) the operator, plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer's buried piping				
	Does the customer notification also go to farm tap customers?				

IV. PART 192 – CORROSION GENERAL		S	N/I	U	N/A
§192.453	(c) Are these procedures under the responsibility of a qualified person?				

V. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
	Did the operator use calibrated half cells?				
§192.455(a)	**For pipelines installed after July 31, 1971:** Are buried segments externally coated & cathodically protected within one year?				
§192.455(b)	For pipelines installed without cathodic protection: Are there any pipelines without cathodic protection?				
	(1) Has the operator proved that a corrosive environment does not exist?				
	(2) Conducted tests within 6-months to confirm (#1) above?				
§192.455	**Pipeline Material Types:** What kinds of pipeline materials are used? Steel, Copper, Plastic, Cast Iron				
§192.455(c)(1)	**For bare copper pipeline:** Is the pipeline cathodically protected if a corrosive environment exists?				
§192.455(c)(2)	**For bare temporary (less than 5 year period of service) pipelines**: For unprotected pipelines, has it been demonstrated that corrosion during the 5-year period will not be detrimental to public safety?				
§192.455(e)	**For aluminum pipeline:** Is the natural pH of the environment <8.0? If not, has operator conducted tests or have experience to indicate the aluminum pipeline suitability with its environment?				x
§192.455(f)	**Metal alloy fittings on plastic pipelines:**				
	(1) Has operator shown by test, investigation, or experience that adequate corrosion control is provided by the alloy composition?				
	(2) Fitting is designed to prevent leakage caused by localized corrosion pitting?				
§192.455(g)	(g) Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of paragraph (f) must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.				
§192.457(a)	**Pipelines installed before August 1, 1971**: Are effectively coated pipelines cathodically protected?				
§192.457(b)	(Except for cast iron or ductile iron) Is cathodic protection provided in areas of active corrosion on:				
	(1) existing bare or ineffectively coated transmission pipelines?				

V. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
	(2) existing bare or coated pipes at compressor, regulator, and measuring stations?				
	(3) existing bare or coated distribution lines?				
§192.459	When the operator has knowledge that any pipeline is exposed, is the exposed pipe examined for:				
	(a) Evidence of corrosion?				
	(b) Coating deterioration?				
§192.459	If external corrosion requiring remedial action is found, is the pipeline investigated circumferentially and longitudinally beyond the exposed portion to determine whether additional corrosion requiring remedial action exists?				
§192.459	Does operator have procedures established for examining exposed **cast iron** pipe for evidence of graphitization?				x
	Does operator have procedures established for remedial measures on **cast iron** pipe if graphitization is discovered, AGA GPTC Appendix G-18 (NTSB)?				x
§192.461(d), (e), (f) & (g)	Steel Transmission: After back fill a coating survey must be conducted and any damage classified as severe must be repaired. The coating survey must be documented and kept for the life of the system.				
§192.463 (a)	Does the level of cathodic protection meet the requirements of Appendix D criteria?				
Appendix D	Steel, cast iron, and ductile iron				
Part I	(1) a negative (cathodic) voltage of at least 0.85 volt ($Cu\text{-}CuSO_4$ ½ cell) also need to consider IR drop				
	(2) a negative voltage shift of at least 300 millivolts (applies to structure not in contact with metals of different anodic potentials) also need to consider IR drop				
	(3) a minimum negative polarization voltage shift of 100 millivolts (interrupting the protective current and measuring the polarization decay)				
	(4) voltage at least as negative as that originally established at beginning of Tafel segment of E-log-I curve				
	(5) net protective current				
	Refer to Appendix D if aluminum, copper, or other metals are within the system also note that other reference cells besides Cu-CuSO4 half-cells can be used if they meet criteria in Section IV of Appendix D				
§192 Appendix D. Part II	Does the operator criteria consider **IR** drop?				
§192.463 (b)	If amphoteric metals are included in a buried or submerged pipeline containing a metal or different anodic potential are they:				
	(1) electrically isolated from the remainder of the pipeline and cathodically protected?; OR				
	(2) cathodically protected at a level that meets the requirements of Appendix D for amphoteric metals?				
§192.463 (c)	Is the amount of cathodic protection controlled to prevent damage to the protective coating or the pipe?				
§192.465(a)	Has each pipeline that is cathodically protected been tested at least once each calendar year not to exceed **15** months?				
§192.465(a)	Are 10 percent of short sections of mains or transmission lines and separately protected service lines distributed over the entire system tested each year on a sampling basis, with a different 10 percent checked each year, so that the entire system is checked in each 10 year period?				

V. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192.465(b)	Has each cathodic protection rectifier been inspected at least **six** times each year not to exceed **2-1/2** months?				
	Each remotely inspected rectifier must be physically inspected at least once each calendar year not exceeding 15 months.				
§192.465(c)	Does the operator check for proper performance of each reverse current switch, diode, and interference bond whose failure would jeopardize structure protection at least **six** times each calendar year, but with intervals not exceeding **2-1/2** months?				
§192.465(c)	Does the operator check for proper performance of other interference bonds at least once each calendar year, at intervals not exceeding **15** months?				
§192.465(d)	Is prompt remedial action taken to correct any deficiencies indicated by the monitoring?				
	(a) Shorted Casings (**6** months)				
	(b) Rectifier (**2-1/2** months)				
	(c) Low p/s readings - case by case, depends on cause				
§192.465(e)	Does the operator have bare pipelines?				
	(a) Are they cathodically protected?				
	(b) Are they reevaluated at **3** year intervals not exceeding **39** months?				
	(c) Are remedial measures taken where necessary?				
§192.465(f)	Transmission: has operator determined the extent of the area with inadequate cathodic protection and mitigated the issue. A close interval survey must be conducted to address systemic causes.				
§192.467	Are buried pipelines electrically isolated from other underground structures?				
	(a) Are casing potentials monitored to detect the presence of shorts once each calendar year, not to exceed 15 months?				
	(b) Does the operator investigate & take appropriate action when indications of casing shorts are found?				
	(c) Does the shorted casing procedure require or has the operator made): (**Enforcement Policy**)				
	(1) Determination of a course of action to correct or negate the effects of the shorts within **6** months of discovery.				
	(2) Verification that a short exists				
	(3) Clearing of the short, if practicable. (This must be considered before alternative measures may be used.)				
	(4) Filling the casing/pipe interstice with high-dielectric casing filler or other material which provides a corrosion inhibiting environment, if it is impractical to clear the short.				
	(5) If (# **3**) & (# **4**) are determined to be impractical, monitor the casing with leak detection equipment for leakage at intervals not exceeding **7-1/2** months, but at least **twice** each calendar year.				
	(6) If a leak is found by monitoring casings with leak detection equipment, immediate corrective action to eliminate the leak & further corrosion.				
	(7) In lieu of other corrective actions, monitoring the condition of the carrier pipe using an internal inspection device at specified intervals.				
§192.467(d)	Inspection and electrical tests must be made to assure that electrical isolation is adequate.				
§192.467(e)	Are insulating devices prohibited in areas where a combustible atmosphere is anticipated unless precautions are made to prevent arcing?				

V. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192.467(f)	Where pipelines are located in close proximity to electrical transmission tower footings, is protection provided to the pipelines against damage due to fault currents?				
§192.469	Are there sufficient test stations or test points?				
§192.473 (a)	Does the operator monitor their system for stray currents and take appropriate steps to minimize detrimental effects?				
§192.473 (b)	Does operator design and install each impressed current and/or galvanic anode cathodic protection system to minimize adverse effects on existing adjacent underground metallic structures?				
§192.473 (c)	For transmission: Interference surveys must be used to detect stray current whenever monitoring indicates a significant increase in stray current or when new potential stray current sources are introduced. Analysis, remedial action plan and remedial action must be completed.				
§192.485 / §192.712	For transmission: Where there any areas of corrosion? Was 192.485 followed? Was 192.712 (Analysis of predicted failure pressure and critical strain level) followed?				

VI. PART 192 – INTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192.475(a)	Is gas tested to determine corrosive properties?				
§192.475(b)	Whenever a pipe segment is removed from a pipeline, is it examined for evidence of internal corrosion?				
	Are filters, strainers, separators and drips checked for liquid? Is it documented? If liquids are found are they required to be analyzed for corrosive properties?				
	If internal corrosion is found -				
§192.475(b)	(1) Is the adjacent pipe investigated to determine the extent of internal corrosion?				
	(2) Is replacement made to the extent required by §§192.485, 192.487, or 192.489?				
	(3) Is remedial action taken (**if required**) to minimize internal corrosion?				
§192.475(c)	Is gas containing >0.25 grain of hydrogen sulfide per 100 ft3 (at standard conditions) may not be stored in pipe-type or bottle-type holders. None in SD.				x
§192.476(a)	Design and construction of **transmission line installed after May 23, 2007:**				
	Has transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line met the following requirements (unless operator proves impracticable or unnecessary):				
	(1) configured to reduce risk liquid collection in line				
	(2) has effective liquid removal features if configuration would allow liquid collection				
	(3) allow for use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion				
§192.476(c)	If operator changes configuration of transmission line, did they evaluate the impact of the change on internal corrosion risk to downstream portion of line and provide for removal of liquids and monitoring of internal corrosion?				
§192.476(d)	Does operator maintain records that demonstrate compliance with this section? Does operator maintain as-built drawings or other construction records if found impracticable or unnecessary to follow (a)(1,2.3)				

VI. PART 192 – INTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192.477	Have coupons **(for corrosive gas only)** been utilized & checked at least **twice** annually not to exceed **7-1/2** months?				
§192.478	Transmission: Additional gas monitoring required when transporting gas with a corrosive constituent. Gas transported in SD is not considered corrosive.				x

VII. PART 192 – ATMOSPHERIC CORROSION CONTROL		S	N/I	U	N/A
§192.481(a)	**Other than a service line:** Does the operator inspect piping exposed to the atmosphere at least once every 3 calendar years, at intervals not to exceed 39 months for onshore piping? **Service Lines:** Does the operator inspect piping exposed to the atmosphere at least once every 5 calendar years, at intervals not to exceed 63 months for onshore piping? If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.				
§192.481(b)	During inspection does the operator give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbanded coating, at pipe supports, at deck penetrations, and in spans over water?				
§192.481(c)	If atmospheric corrosion is found, does the operator provide protection against the corrosion as required by §192.479?				

VIII. PART 192 – REMEDIAL MEASURES		S	N/I	U	N/A
§192.483	Is replacement steel pipe coated and cathodically protected?				
§192.485(a)	For each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline, is the section of pipeline replaced, repaired, or have the operating pressure reduced?				
§192.485(b)	For each segment of transmission line with localized pitting to a degree where leakage might result, is the section of pipeline replaced, repaired, or have the operating pressure reduced?				
§192.485(c)	Strength of pipe based on actual remaining wall thickness may be determined by 192.712				
§192.487(a)	For distribution lines with a remaining wall thickness less than that required for the MAOP of the pipeline or a remaining wall thickness less than 30 percent of the nominal wall thickness, does the operator replace or repair the pipe?				
§192.487(b)	For distribution lines, does the operator replace or repair pipe with localized corrosion pitting?				
§192.489(a)	Is each segment of cast iron or ductile iron pipe on which **general** graphitization is found to a degree where a fracture or any leakage might result, replaced?				
§192.489(b)	Is each segment of cast iron or ductile iron pipe on which **localized** graphitization is found to a degree where any leakage might result, replaced or repaired, or sealed by internal sealing methods?				
§192.714	**Repair Criteria** Transmission –not located in an HCA: Repair Criteria Have any repairs been made? Are all conditions of 192.714 met?				
§192.715	**Permanent field repair of welds** Is each weld found not acceptable under 192.241(c) repaired properly?				

VIII. PART 192 – REMEDIAL MEASURES		S	N/I	U	N/A
§192.717	**Permanent field repair of leaks.** Do weld repairs meet the following? Each permanent field repair of a leak on a transmission line must be made by- (a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or (b) Repairing the leak by one of the following methods: (1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS. (2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp. (3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size. (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design. (5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.				
§192.719	Is replacement pipe tested to the requirement of a new line installed in the same location and records maintained as required under Subpart J Testing Requirements? (Note: the pipe may be tested before it is installed) Is it examined in accordance with 192.241?				

IX. PART 192 – CORROSION CONTROL RECORDS		S	N/I	U	N/A
§192.491(a)	Does the operator maintain records or maps showing the location of cathodically protected pipe and facilities?				
§192.491(b)	Does the operator retain records showing the location of cathodically protected pipe and facilities for the life of the system?				
§192.491(c)	Does the operator maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate adequacy of corrosion control measures or that a corrosive condition does not exist for at least 5 years?				
§192.491(c)	Does the operator retain records related to §§192.465(a) and (e) and 192.475(b) retained for as long as the pipeline remains in service? External corrosion monitoring and internal corrosion monitoring records must be retained for the life of the system. Atmospheric corrosion monitoring only needs to be kept for the last two inspections.				

X. PART 192 – CHANGE IN CLASS LOCATION		S	N/I	U	N/A
§192.609	(Transmission >40% SMYS) **Has the operator determined that a class location study is required?** Class location study – When increase in population density indicates a change in class location or indicates that the hoop stress corresponding to the established maximum allowable operating pressure for a segment of existing pipeline is not commensurate with the present class location, the operator shall immediately make a study to determine: (a) The present class location for the segment involved. (b) The design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location by the applicable provision part. (c) The physical condition of the segment to the extent it can be ascertained from available records. (d) The operating and maintenance history of the segment. (e) The maximum actual operating pressure and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved. (f) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.				
§192.610	If there is a class location change and pipe is replaced, then a review of the valve spacing and rupture mitigation valves much be completed. (see code)				
§192.611	**Confirmation or revision of MAOP -** Is the MAOP confirmed or revised according to 192.611?				
	(b) Reduce MAOP to meet the class location.				
	(c) Replace pipe.				
	Refer to 192.611 if MAOP is confirmed or revised (also see Subpart K if applicable)				
General	Does the operator have the appropriate class locations defined?				

XI. PART 192 – ODORIZATION OF GAS		S	N/I	U	N/A
	Did the operator use calibrated odorometers? What kind of equipment is used?				
§192.625(a)	Chemical Properties - Brand Name –				
One-Fifth of the Lower Explosive Limit	Odorometer				
	Injection Rate				
	Odorization Method –				
§192.625(b)	Transmission Lines in Class 3 or 4 locations must comply with 192.625(a) if 50% or less of the length of the line downstream is in a Class 1 or 2 location. There are also other exceptions found within this section				
§192.625(e)	Does the equipment introduce the odorant without wide variations in the level of odorant?				
§192.625(f)	Does the operator conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable?				
	How are farm tap customers odorant levels checked? Review documentation.				

XII. PART 192 – MAINTENANCE		S	N/I	U	N/A
§192.703(b)	Is each segment of a pipeline that becomes unsafe, replaced, repaired or removed from service?				
§192.703(c)	Are hazardous leaks repaired promptly?				

XIII. PART 192 – PATROLLING TRANSMISSION			S	N/I	U	N/A
§192.705(a)	Does the operator patrol surface conditions for indications of leaks, construction activity, or other factors on and adjacent to line ROW?					
	(a) Does the operator follow up on problems noted?					
§192.705(b)	Is the maximum interval between patrols in accordance with the following: **(Maximum interval between patrols of lines)**					
Class location	At Highway and Railroad Crossings	At all Other Places				
1 and 2	**2/yr (7-1/2 months)**	**1/Year (15 months)**				
3	**4/yr (4-1/2 months)**	**2/yr (7-1/2 months)**				
4	**4/yr (4-1/2 months)**	**4/yr (4-1/2 months)**				

XIV. PART 192 – LEAK SURVEYS: TRANSMISSION		S	N/I	U	N/A
	Did the operator use calibrated leak detectors? What kind of equipment is used?				
§192.706	(a) Are leakage surveys of transmission lines conducted at intervals not exceeding 15 months but at least once each calendar year?				
	(b) Are lines transporting unodorized gas surveyed using leak detector equipment at intervals not exceeding 7-1/2 months but at least twice each calendar year for Class 3 locations and at intervals not exceeding 4-1/2 months but at least 4 times each calendar year for Class 4 locations?				

XV. PART 192 – LINE MARKERS		S	N/I	U	N/A
	Inspected in the field.				
§192.707(a)	Are buried mains and transmission lines marked as required in the following areas:				
	(1) at each crossing of a public road and railroad		x		
	(2) wherever necessary to identify the location of the line to reduce possibility of damage or interference		x		
§192.707(b)	EXCEPTIONS where line markers are NOT required:				
	(1) lines located at crossings of or under waterways and other water bodies		x		
	(2) mains in Class 3 or 4 location where damage prevention program is in effect under §192.614		x		
	(4) transmission lines in Class 3 or 4 locations where placement of line marker is impractical		x		
§192.707(c)	Are line markers installed on aboveground areas accessible to the public?		x		
§192.707(d)	Do the line markers have the latest characteristics?				
	(1) “Warning”, “Caution”, “Danger” followed by “Gas Pipeline” (1” high with ¼” stroke except in heavily developed areas)		x		
	(2) name and telephone number of operator (24 hr access)		x		

XVI. PART 192 – PATROLLING DISTRIBUTION		S	N/I	U	N/A
§192.721(a)	Frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage (i.e., consider cast iron, weather conditions, known slip areas, etc.)				
§192.721(b)(1)	Does the operator patrol mains in business districts at intervals not exceeding **4-1/2** months, but at least **4** times each calendar year where anticipated physical movement or external loading could cause failure or leakage?				
§192.721(b)(2)	Does the operator patrol mains outside business districts at intervals not exceeding **7-1/2** months, but at least **2** times each calendar year where anticipated physical movement or external loading could cause failure or leakage?				

XII. PART 192 – SURVEILLANCE		S	N/I	U	N/A
§192.613(a)	Has the operator conducted continuing surveillance to determine if the following issues need to be addressed: - Change in class location - Failures - Leakage history - Corrosion - Cathodic protection - Other unusual conditions Review documentation of issues operator feels needs to address.				
§192.613(b)	Has the operator documented and initiated a program to correct problems discovered?				
§192.613(c)	Is there a documentation for inspecting transmission facilities after an extreme weather event or natural disaster? Was the inspection required started within 72 hours? What remedial action was taken?				

XVII. PART 192 – LEAKAGE SURVEYS: DISTRIBUTION		S	N/I	U	N/A
	Did the operator use calibrated leak detectors? What kind of equipment is used?				
§192.723(b)(1)	Does the operator conduct gas detector surveys in the business district at intervals not exceeding 15 months, but at least once each calendar year?				
	Has the operator appropriately defines business districts?				
192.723	Review the records for leak survey of inside meter sets.				
§192.723(b)(2)	Does the operator conduct leakage surveys (to include manholes/cracks in pavement/other pertinent locations) of the distribution system outside of the principal business areas at intervals not exceeding 63 months, but at least once every 5 calendar year?				
§192.723(b)(2)	For cathodically unprotected distribution lines subject to §192.465(e) on which electrical surveys for corrosion are impractical is a leakage survey conducted at least once every 3 calendar years at intervals not exceeding 39 months?				

XVIII. PART 192 – VALVE MAINTENANCE: TRANSMISSION		S	N/I	U	N/A
§192.179	If a new line was installed or replaced, does it have the appropriate valve spacing and have rupture-mitigation valves as required? Rupture rule – see also 192.634, 192.635 and 192.636 for additional requirements.				
§192.745(a)	Does the operator check and service each valve which might be required during an emergency at intervals not exceeding 15 months, but at least once each calendar year?				
§192.745(b)	Does the operator take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve?				
§192.745(c)	Each remote-control valve (RCV) must have a point-to point verification between SCADA system and the valve.				
§192.745(d)	For alternative equivalent technology where a valve is manually or locally operated operators much achieve closure in 30 minutes or less through an initial and periodic review.				

XIX. PART 192 – VALVE MAINTENANCE: DISTRIBUTION		S	N/I	U	N/A
§192.747(a)	Does the operator check and service each valve which might be required during an emergency at intervals not exceeding 15 months, but at least once each calendar year?				
§192.747(b)	Does the operator take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve?				

XX. PART 192 – VAULTS		S	N/I	U	N/A
	Currently not aware of any vaults in SD.				
§192.749(a)	Is each vault that houses pressure regulating and limiting equipment (and has an internal volume of 200 ft^3 or more) inspected at least once each calendar year not exceeding 15 months? Vaults need to be inspected to determine if they are in good physical condition and adequately vented. (Vault is defined as "An underground structure which may be entered, and which is designed to contain piping and piping components, such as valves or pressure regulators.")				
§192.749(b)	If gas was found in vault during inspection was equipment inspected for leaks? If leaks were found were they repaired?				
§192.749(c)	Was ventilating equipment inspected to determine if functioning properly?				
§192.749(d)	Was vault cover inspected to assure it does not present hazard to public safety?				
§192.727(f)	If any vaults were abandoned, were they filled with a suitable compacted material?				

XXI. PART 192 – DIMP/TIMP		S	N/I	U	N/A
	Discuss actions that the operator has been taking for their DIMP/TIMP plan.				
	Have there been any indications of Di-thiazine in your pipelines?				