Chris Nelson, Chairman
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Gary Hanson, Commissioner

South Dakota
PUBLIC UTILITIES COMMISSION
500 East Capitol Avenue
Pierre, South Dakota 57501-5070
www.puc.sd.gov

(605) 773-3201

Consumer Hotline
1-800-332-1782

Email
puc@state.sd.us

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Patricia Van Gerpen
Executive Director
SD Public Utilities Commission
500 E. Capitol Ave.
Pierre, SD 57501

RE: Waiver of certain code requirements identified in PHMSA Amendment 192-128

Ms. Van Gerpen:

PHMSA published an amendment (Amdt. 192-128) in January with an effective date of March 21, 2021. This amendment titled "Gas Pipeline Regulatory Reform" included regulations that lessened the burden on natural gas operators.

South Dakota has not yet adopted the amendment. Currently only amendments through January 1, 2019 are adopted per SDCL 49-34B-3. Even though Senate Bill 37, which changes the date to January 1, 2021 was signed by Governor Noem and will be effective July 1, 2021, the Amendment 192-128 was published after January 1, 2021, and these regulations will not take effect for South Dakota until after SDCL 49-34B-3 is amended.

I propose that we allow operators to apply the new regulation immediately rather than waiting for SDCL 49-3B-3 to be updated. Rather than having each operator request a waiver, I propose a general waiver that applies to all natural gas operators in South Dakota. Since this is already in federal code the waiver will not need to be approved by PHMSA.

Amendment 192-128 makes the following code sections less restrictive:

1. 49 CFR 191.3 changed the definition of "incident". That revision changes the reporting requirement for property damage from $50,000 or more to $122,000 or more.

2. 49 CFR 192.281 allows an alternative procedure to be used for plastic pipe heat fusion joints.

3. 49 CFR 192.465 allows for rectifiers and impressed current systems to be monitored remotely and only requires an in person inspection done once a year rather than 6 times each year.

4. 49 CFR 192.481 was revised to allow operators to do atmospheric corrosion monitoring on a 5-year interval rather than the 3-year interval previously required.

Additionally, NorthWestern Energy and Montana Dakota Utilities have a waiver for this requirement which allows the them to complete atmospheric corrosion in conjunction with leak survey on a 4-year cycle. (See PS07-001 and PS18-002.) This change would then make those waivers unnecessary.

I have attached a document that shows the changes that occurred to each of the code sections mentioned above.

Sincerely,

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Mary Zanter
Pipeline Safety Program Manager

49 CFR code sections language after Amendment 192-128 with new language shown in red text.

§191.3 Definitions.

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Incident means any of the following events:

(1) An event that involves a release of gas from a pipeline, gas from an underground natural gas storage facility (UNGSF), liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility, and that results in one or more of the following consequences:

(i) A death, or personal injury necessitating in-patient hospitalization;

(ii) Estimated property damage of ~~$50,000~~ $122,000 or more, including loss to the operator and others, or both, but excluding the cost of gas lost. For adjustments for inflation observed in calendar year 2021 onwards, changes to the reporting threshold will be posted on PHMSA's website. These changes will be determined in accordance with the procedures in appendix A to part 191.

(iii) Unintentional estimated gas loss of three million cubic feet or more.

(2) An event that results in an emergency shutdown of an LNG facility or a UNGSF. Activation of an emergency shutdown system for reasons other than an actual emergency within the facility does not constitute an incident.

(3) An event that is significant in the judgment of the operator, even though it did not meet the criteria of paragraph (1) or (2) of this definition.

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§192.281 Plastic pipe.

(a) *General*. A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.

(b) *Solvent cement joints*. Each solvent cement joint on plastic pipe must comply with the following:

(1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint.

(2) The solvent cement must conform to ASTM D2564-12 for PVC (incorporated by reference, *see* § 192.7).

(3) The joint may not be heated or cooled to accelerate the setting of the cement.

(c) *Heat-fusion joints*. Each heat fusion joint on a PE pipe or component, except for electrofusion joints, must comply with ASTM F2620 (incorporated by reference in § 192.7), or an alternative written procedure that has been demonstrated to provide an equivalent or superior level of safety and has been proven by test or experience to produce strong gastight joints, and the following:

(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under § 192.283.

(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously, to establish the same temperature. The

device used must be the same device specified in the operator's joining procedure for socket fusion.

(3) An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer, or using equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be equivalent to or better than the requirements of the fitting manufacturer.

(4) Heat may not be applied with a torch or other open flame.

(d) *Adhesive joints*. Each adhesive joint on plastic pipe must comply with the following:

(1) The adhesive must conform to ASTM D 2517. (incorporated by reference, *see* §192.7)

(2) The materials and adhesive must be compatible with each other.

(e) *Mechanical joints*. Each compression type mechanical joint on plastic pipe must comply with the following:

(1) The gasket material in the coupling must be compatible with the plastic.

(2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling.

(3) All mechanical fittings must meet a listed specification based upon the applicable material.

(4) All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.

§192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission lines, not in excess of 100 feet (30 meters), or separately protected service lines, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period.

~~(b) Each cathodic protection rectifier or other impressed current power source must be inspected six times each calendar yar but with intervals not exceeding 2 ½ months, to ensure that it is operating.~~

(b) Cathodic protection rectifiers and impressed current power sources must be periodically inspected as follows:

(1) Each cathodic protection rectifier or impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months between inspections, to ensure adequate amperage and voltage levels needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.

(2) After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months.

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each

calendar year, but with intervals not exceeding 2½ months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.
(d) Each operator shall take prompt remedial action to correct any deficiencies indicated by the monitoring.
(e) After the initial evaluation required by §§192.455(b) and (c) and 192.457(b), each operator must, not less than every 3 years at intervals not exceeding 39 months, reevaluate its unprotected pipelines and cathodically protect them in accordance with this subpart in areas in which active corrosion is found. The operator must determine the areas of active corrosion by electrical survey. However, on distribution lines and where an electrical survey is impractical on transmission lines, areas of active corrosion may be determined by other means that include review and analysis of leak repair and inspection records, corrosion monitoring records, exposed pipe inspection records, and the pipeline environment.

§192.481 Atmospheric corrosion control: Monitoring.
(a) Each operator must inspect and evaluate each pipeline or portion of the pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

Pipeline type:	**Then the frequency of inspection is:**
(1) Onshore other than a Service Line	At least once every 3 calendar years, but with intervals not exceeding 39 months.
(2) Onshore Service Line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.
(3) Offshore	At least once each calendar year, but with intervals not exceeding 15 months.

(b) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.
(c) If atmospheric corrosion is found during an inspection, the operator must provide protection against the corrosion as required by Sec. 192.479.
(d) 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.