(c) The contracting officer shall insert the clause at 552.238–74, Submission and Distribution of Authorized GSA Schedule Pricelists, in solicitations and contracts awarded under the multiple award schedule program. When GSA is not prepared to accept electronic submissions for a particular schedule, the contracting officer is authorized to modify the clause by deleting subparagraph (c)(1)(ii) and (c)(3) and modifying subparagraph (c)(1) to eliminate "(i)" and the word "and" at the end of subparagraph (i).

PART 552—SOLICITATION PROVISIONS AND CONTRACT CLAUSES

3. Section 552.238–74 is added to read as follows:

552.238–74 Submission and distribution of authorized GSA schedule pricelists.

As prescribed in 538.203–71(c), insert the following clause:

SUBMISSION AND DISTRIBUTION OF AUTHORIZED GSA SCHEDULE PRICELISTS (SEP 1993)

(a) Definition. For the purposes of this clause, the Mailing List is [Contracting officer shall insert either: "the list of Federal addressees provided to the Contractor by the Contracting Officer" or "the Contractor's listing of its Federal government customers"].

(b) The Contracting Officer will return one copy of the Authorized GSA Schedule Pricelist to the Contractor with the notification of contract award. The Contractor shall not print or distribute the pricelist without written approval from the Contracting Officer. NOTE: Approval by the Contracting Officer shall not absolve the contractor from responsibility for the accuracy of the pricelist.

(c)(1) The Contractor shall provide to the GSA Contracting Officer:

(i) Two paper copies of Authorized GSA Schedule Pricelist; and

(ii) The Authorized GSA Schedule Pricelist on a common-use electronic medium.

The Contracting Officer will provide detailed instructions for the electronic submission with the award notification. Some structured data entry in a prescribed format may be required.

(2) The Contractor shall provide to each addressee on the mailing list either:

(i) One paper copy of the Authorized GSA Schedule Price List; or

(ii) A self-addressed, postage-paid envelope or postcard to be returned by addressees that want to receive a paper copy of the pricelist. The Contractor shall distribute price lists within 20 calendar days after receipt of returned requests.

(3) The Contractor shall advise each addressee of the availability of pricelist information through the on-line Multiple Award Schedule electronic data base.

(d) The Contractor shall make all of the distributions required in paragraph (c) at least 15 calendar days before the beginning of the contract period, or within 30 calendar days after receipt of the Contracting Officer's approval for printing, whichever is later.

(e) During the period of the contract, the contractor shall provide one copy of its Authorized GSA Schedule Pricelist to any authorized schedule user, upon request. Use of the mailing list for any other purpose is not authorized.

(End of Clause)

Dated: October 5, 1993.

Richard H. Hopf, III,

Associate Administrator for Acquisition Policy.

[FR Doc. 93–25947 Filed 10–21–93; 8:45 am]

BILLING CODE 6820-61-M

DEPARTMENT OF TRANSPORTATION

Research and Special Programs Administration

49 CFR Part 192

[Docket PS–123; Amdt. 192–70]

RIN 2137–AB64

Leakage Surveys on Distribution Lines Located Outside Business Districts

AGENCY: Research and Special Programs Administration (RSPA), DOT.

ACTION: Final rule.

SUMMARY: This final rule requires operators of distribution lines located outside business districts to use leak detectors to carry out required leakage surveys. Instead of using leak detectors, some operators survey for leaks by looking for dead or dying vegetation, a less reliable method. The rule will provide greater assurance that operators identify all hazardous leaks during required leakage surveys..

Also, where electrical surveys for corrosion are impractical on cathodically unprotected metallic distribution lines located outside business districts, operators commonly use leakage survey data to determine whether the lines are corroding. However, under the present leakage survey standard, those data may be too old for purposes of evaluating lines for corrosion at 3-year intervals. Thus, the final rule assures that leakage survey data no more than 3 years old are used to evaluate lines for corrosion.

EFFECTIVE DATE: November 22, 1993.

FOR FURTHER INFORMATION CONTACT: L.M. Furrow, (202) 366–2392, regarding the subject matter of this final rule, or the Dockets Unit, (202) 366–5046, regarding copies of this final rule document or other material in the docket.

SUPPLEMENTARY INFORMATION:

Background

A string of accidents due to corrosion and other causes occurred on residential service lines operated by the Kansas Power and Light Company (KPL) in Kansas and Missouri during a 7-month period of 1988 and 1989. Overall, four persons were killed and 16 were injured, with property damage exceeding $740,000. The service lines were mostly steel lines installed by contractors of the operator's customers before issuance of the gas pipeline safety standards in 49 CFR part 192.

The lines had been checked for leaks through vegetation surveys carried out by KPL's meter readers, but KPL had never used gas detectors to survey the lines for leaks. Responding to the accidents, KPL conducted a comprehensive gas detector survey that revealed 2,156 leaks in 55,213 house service lines. KPL considered 303 of these leaks to need immediate repair.

After the KPL accidents, the National Transportation Safety Board (NTSB) recommended the following to RSPA:

- Amend the provisions of 49 CFR part 192 that allow alternatives to the use of electric surveys for identifying areas of active corrosion to require that any alternative must provide data equivalent, both in timeliness and quality, to that obtained using electrical surveys. (P–90–17)
- Amend 49 CFR part 192 to disallow the use of vegetation-type surveys for complying with any leakage survey requirement. (P–90–18)

In addition, the National Association of Pipeline Safety Representatives (NAPSR), an organization of State pipeline inspectors, has recommended that operators use gas detectors in leakage surveys on distribution lines. NAPSR believes that vegetation surveys are too imprecise to assure safety in residential areas.

Vegetation surveys are based on the assumption that a high proportion of natural gas in the subsurface environment displaces air in the soil. Lack of air inhibits the growth of vegetation, producing an effect visible on the ground. Hence, observation of dead or dying vegetation is used to infer the existence of an underground gas leak. While the vegetation survey is a well-established technique, it suffers from a number of weaknesses. At various times of the year, primarily because of seasonal, weather, or climatical conditions, the growth of vegetation is insufficient to support a proper vegetation survey. In addition, vegetation is noticeably affected only after gas has leaked at a significant rate for a significant time. Thus, vegetation surveys may not discover incipient leaks; and very small, or "pinhole," leaks may not be discovered unless they increase in size.

In contrast, leakage surveys using portable gas detector equipment can be done at any time of the year. Although the sensitivity of available gas detectors varies, all equipment can detect the presence of natural gas in the atmosphere without the aid of human judgment. Consequently, the uncertainty associated with vegetation surveys is eliminated with gas detector surveys. Whenever a trained technician does a gas detector survey, the operator can assume with reasonable certainty that all hazardous leaks will be found.

Notice of Proposed Rulemaking

Because of the KPL accidents and the NTSB and NAPSR recommendations, RSPA proposed to strengthen the rule that governs leakage surveys of gas distribution lines in residential areas (§ 192.723(b)(2)). In a notice of proposed rulemaking (NPRM) published October 23, 1991 (56 FR 54816), RSPA proposed to require that operators use gas detection equipment in leakage surveys under § 192.723(b)(2). (Operators who survey their lines for leaks more often than once every 5 years, the minimum frequency under § 192.723(b)(2), could continue to use vegetation surveys for those additional leakage surveys.) At the same time, RSPA proposed to clarify § 192.723(b)(2) and make it consistent with § 192.723(b)(1) by replacing the phrase, "outside of the principal business areas," with "outside business districts."

Another proposed amendment of § 192.723(b)(2) concerned cathodically unprotected metallic distribution lines that must be evaluated for corrosion under § 192.465(e). Operators must evaluate these pipelines at least every 3 years to determine whether areas of active corrosion exist on the lines. Areas of active corrosion must be determined by electrical survey, or if an electrical survey is impractical, by the study of corrosion and leak history records, by leak detection survey, or by other means.

It is common practice for operators to rely on leakage surveys as an alternative to electrical surveys in complying with § 192.465(e). RSPA's concern is that when only 5-year-old data collected under § 192.723(b)(2) are used for this purpose, corrosion may go unchecked on distribution lines in residential areas longer than the 3 years that § 192.465(e) allows. Therefore, RSPA proposed to amend § 192.723(b)(2) to require that when electrical surveys are impractical on cathodically unprotected distribution lines that are subject to § 192.465(e), leakage surveys must be done at least every 3 years.

Disposition of Comments

The 56 organizations that filed comments on the NPRM are categorized as follows:

Federal agency—2: NTSB, U.S. Environmental Protection Agency (EPA)
State pipeline agency—6: Oregon, Kansas, Iowa, Massachusetts, Kentucky, Maryland
Trade association—3: American Gas Association (AGA), NY Gas Group, Oil Heat Task Force
Professional association—1: Gas Piping Technology Committee
Leak survey business—1: Southern Cross
Consultant—1: ConReg Associates
Distribution operator—42: Alagasco; ARKLA; Atlanta Gas Light Company; Atmos Energy Corporation; Boston Gas Company; The Brooklyn Union Gas Company; Citizens Gas and Coke Utility; Colorado Springs Utilities; The Columbia Distribution Companies; Consolidated Edison Company of N.Y., Inc.; Consumers Power Company; The East Ohio Gas Company; Entex; Equitable Resources, Inc.; Hope Gas, Inc.; Iowa-Illinois Gas and Electric Company; Laclede Gas Company; Louisiana Gas Service Company; Minnegasco; Mississippi Valley Gas Company; Montana-Dakota Utilities Co.; Mountain Fuel Supply Company; National Fuel Gas Distribution Corporation; Natural Gas Pipeline Company of America; New York State Electric and Gas Corporation; Northern Indiana Public Service Company; Northern Illinois Gas; Northern Minnesota Utilities; Northwest Natural Gas Company; Okaloosa County Gas District; Oklahoma Natural Gas Company; Pacific Gas and Electric Company; The Peoples Gas Light and Coke Company; Peoples Gas System, Inc.; The Peoples Natural Gas Company; Philadelphia Electric Company; Public Service Company of Colorado; Southern California Gas Company; Southwest Gas Corporation; Washington Gas; Willmut Gas & Oil Company; Wisconsin Natural Gas Co.

Gas Detector v. *Vegetation Survey*

Some 50 commenters addressed the issue of whether operators should be required to use gas detectors in leakage surveys of distribution systems outside business districts. Of these commenters, 16, including NTSB, Oregon, Kansas, Massachusetts, Maryland, NY Gas Group, Oil Heat Task Force, and 9 distribution operators, voiced general support for the proposal. Another 17 commenters, all distribution operators, supported the proposal because they now use gas detectors, either hydrogen flame ionization equipment or combustible gas indicators, or both, in their surveys.

Two distribution operators supported the proposal, but preferred that the final rule use the term "instrumented leak detection equipment" instead of "gas detector." They said this change would allow the use of sonics for leakage surveys, a technology that does not rely on actual detection of gas. This comment is important because RSPA does not want the final rule to deter the use of advancements in leakage survey technology. In addition, § 192.706, governing leakage surveys of transmission lines, requires the use of "leak detector equipment." To be consistent with § 192.706, final § 192.723(b)(2) uses the term "leakage survey with leak detector equipment" instead of "gas detector survey." For consistency, we also replaced "gas detector survey" in § 192.723(b)(1) with "leakage survey with leak detector equipment."

Three other distribution operators supported the proposal, but suggested we limit the final rule to buried pipe. They saw no need to include interior piping under the leakage survey requirement, stating that leaks inside buildings are readily detectable without gas detectors. However, existing § 192.723(b)(2) requires leakage surveys on interior piping that is subject to part 192. Although the NPRM did not propose to alter this requirement, RSPA does not agree that there is no need for leakage surveys on interior piping. Many people have a diminished sense of smell, and conceivably could not readily smell odorized gas escaping from a pinhole leak. Periodic interior leakage surveys protect against accidents caused by otherwise undetected leaks.

Several commenters thought the term "business district" should be defined in the final rule. Two of these commenters referred to the definition in the *Guide for Gas Transmission and Distribution Piping Systems.* One asked that we define the term to distinguish older innercity business areas from newer commercial developments. RSPA did not adopt these comments because the term "business district" has been used in § 192.723(b)(1) since the rule's inception without significant compliance difficulties.

Two commenters thought we should define "gas detector survey." As discussed above, the final rule uses "leakage survey with leak detector equipment" instead of "gas detector survey." RSPA believes this alternative term is clear and needs no definition.

Another commenter disliked the term "gas detector survey" because it would allow use of combustible gas indicators, a method the commenter said is not as effective as hydrogen flame ionization equipment. The NPRM did not propose to standardize the equipment operators may use in conducting leakage surveys. Rather, the purpose of the proposal was to disallow the use of vegetation surveys to meet leakage survey requirements. So any kind of equipment capable of detecting leaks in gas distribution systems may be used under the final rule.

Several commenters opposed the gas detector proposal because they favored the continued use of vegetation surveys to meet leakage survey requirements. One said that vegetation surveys are 35% effective on a single pass (compared to 85 percent for hydrogen flame ionization equipment), 5 times faster than hydrogen flame ionization equipment, and 20 percent as expensive. This commenter said vegetation surveys are reliable if run by trained personnel at frequent intervals (2 or 3 times as often as hydrogen flame ionization). Two other commenters argued that an abundance of vegetation is available for efficient scheduling and running of effective vegetation surveys. One of these commenters also said a recent trial survey with gas detectors produced only 5% more leaks than a vegetation survey, and they were of low priority.

RSPA does not find these arguments persuasive. The above statistics themselves show that vegetation surveys are less effective than leak detector equipment on a single pass over distribution lines, even when using trained personnel. Also, the savings in time and money seem to be offset by the need to run vegetation surveys more often for results as reliable as with gas detectors. This need for more frequent surveys is not compatible with the 5-year minimum frequency specified by § 192.723(b)(2). Further, while vegetation is essential for vegetation surveys, abundant vegetation does not overcome these drawbacks: leaks must be inferred rather than detected, and incipient leaks need time before they visually affect vegetation. The fact that a commenter found only minor additional leaks with leak detector equipment is fortunate but not necessarily typical, as the KPL experience shows. Moreover, undetected minor leaks can grow to become hazardous.

One commenter argued against the mandatory use of gas detectors by asserting that most leaks are reported through odorization of gas. Only 10 percent or less are found by leakage surveys the commenter said. Even so, public safety demands that operators use reliable means to discover leaks not reported through odorization. Gas detectors, unquestionably, are more reliable than vegetation surveys. And our analysis shows that gas detectors can be used to meet the present leakage survey rule at minimal additional cost. Thus, RSPA believes that disallowing the use of vegetation surveys to meet that rule is reasonable.

AGA opposed the proposal on the ground that one company's results are inadequate justification to change § 192.723(b)(2). AGA also saw only minimal potential benefits from mandatory gas detector surveys, because since 1984 there have been only 57 distribution incidents caused by corrosion, with 6 deaths, 39 injuries, and $2.35 million of property damage. However, RSPA notes that the KPL accidents were not the sole justification for proposing to change § 192.723(b)(2). The NPRM was also based on an analysis of the effectiveness of vegetation surveys, on recommendations by NTSB and NAPSR, and the fact that Kansas, Missouri, and other states have required operators to use gas detectors in residential leakage surveys. Moreover, corrosion is not the only cause of leaks on distribution lines located outside business districts. Outside force damage to pipe is a major cause of leaks, as are pipeline construction and material defects. These other causes of leaks add to the corrosion-related benefits of leakage surveys. As with corrosion, leaks from these other causes can result long after the damage or defect occurs, creating an opportunity for the operator to discover the leak during a leakage survey.

One commenter asked that RSPA exempt lines in unoccupied rural areas where steep terrain and high vegetation growth limit the effectiveness of gas detector surveys. Although leakage surveys with gas detectors may take longer in areas of steep terrain and high vegetation, RSPA does not have evidence that such surveys are less effective in those areas. Considering the allowable interval between required surveys (5 years), RSPA feels operators have ample time to survey lines in those areas with leak detection equipment. The final rule does not have the suggested exemption.

Corrosion Evaluation by Leakage Survey

Forty-two commenters addressed the issue of whether cathodically unprotected pipe subject to the 3-year electrical survey requirement of § 192.465(e) should be surveyed for leaks at least every 3 years if electrical surveys are impractical. Of these commenters, 16, includinq NTSB, Southern Cross, Kansas, Iowa, Massachusetts, Oil Heat Task Force, and 10 distribution operators, expressed general support for the proposal. Another 7 of the 42, all distribution operators, said they supported the proposal because they now survey their unprotected lines for leaks at 3-year intervals.

Four distribution operators supported the proposal, but suggested that the proposed frequency (intervals not exceeding 3 years) be changed to read "at intervals within 3 calendar years, but not exceeding 39 months." They said this change would be consistent with other part 192 requirements for periodic inspections by allowing time to cope with extreme weather conditions. RSPA agrees that in scheduling leakage surveys to comply with the rule, operators will have to consider the weather. However, 3 years should be ample time within which to schedule and conduct a survey in good weather. None of the present part 192 standards that prescribe inspections every 3 years allow more than 36 months between inspections (e.g., § 192.465(e)).

Three commenters, including AGA, opposed the proposal on the ground that every 3 years is too frequent to check for leaks, given the low corrosion accident rate. They suggested we extend the 3-year electrical survey minimum frequency to 5 years to match the minimum leak survey frequency. This change, they said, would reduce compliance cost with no adverse safety impact. RSPA did not adopt this approach, because it would weaken the existing rule on monitoring unprotected metallic pipelines for corrosion (§ 192.465(e)). This rule was established to hold down the corrosion accident rate on distribution lines. The low corrosion accident rate that has been attained with this rule is not a sufficient reason to slacken the minimum frequency of corrosion monitoring.

Four distribution operators opposed the proposal because they felt the use of 5-year old leak survey data has not caused a safety problem. One of these commenters pointed out that under § 192.465(e), the use of leak history data as an alternative to electrical surveys includes data from sources besides leak surveys, such as reports from the public. Another of these commenters thought the existing § 192.723(b)(2) is satisfactory because it requires surveys "as frequently as necessary." Similarly, another of the four said the use of improved leak survey techniques and reliance on corrosion and leak history are sufficient measures under § 192.465(e) to insure pipeline integrity, without more frequent surveys.

RSPA did not change the final rule as a result of these comments. The available safety data are insufficient to substantiate the commenters' assertion that using 5-year old data to meet a 3-year monitoring rule has not caused a safety problem. In the absence of such information, since pipeline corrosion continues to pose a serious threat to public safety, it is reasonable to require that unprotected pipelines be evaluated for corrosion on the basis of current data. Admittedly, the other considerations the commenters mentioned compensate to some degree for the use of out-of-date leak survey data. However, in our opinion, they do not overcome the need for leak survey data that reflect the state of corrosion activity within the prescribed period of evaluation.

Five operators opposed the proposal because of the scattered nature of unprotected parts of their distribution systems. For cost effective leakage surveys, these commenters said they would have to survey areas of their systems at 3-year intervals regardless of whether the areas contain protected or unprotected lines. It would be too impractical, they said, to survey unprotected lines selectively at 3-year intervals and the remainder at 5-year intervals. One operator suggested that changing the 5-year survey requirement to 6 years would alleviate this problem.

In response to these operators, RSPA notes that under § 192.465(a), protected lines must be monitored at least annually, while under § 192.465(e), operators have as long as 3 years to monitor unprotected lines. Thus, distribution systems with both protected and unprotected pipelines are already subject to different intervals for corrosion monitoring. In RSPA's experience, operators have not had significant trouble in applying these different monitoring intervals to separate parts of their systems. Since the proposed 3-year leakage survey is merely a means of carrying out the 3-year corrosion monitoring requirement on unprotected pipelines, RSPA does not believe it would add to the operators' present burden of compliance with § 192.465(e). Therefore, RSPA was not persuaded to alter the final rule because of the alleged impracticality of surveying different parts of a system at different rates. Moreover, the prescribed intervals under final § 192.723(b)(2) are maximum times between surveys. Operators who find it more convenient to survey separate parts of their systems at compatible frequencies, such as 2 and 4 years, or at the same frequency, such as every 3 years, may do so, provided the prescribed intervals are not exceeded.

Specific Comments Requested

In the NPRM, RSPA announced that it was reconsidering the need for more frequent leakage surveys on all distribution lines outside business districts. In that regard, we requested comments on the following topics to help us decide whether to propose a 1-year minimum frequency for leakage surveys on unprotected lines and a 3-year minimum frequency on all other lines.

(1) The need to increase from every 5 years to every 3 years the minimum frequency of leakage surveys on distribution lines of any material located outside business districts.

Only four commenters supported the notion of increasing from every 5 years to every 3 years the minimum frequency required for leak surveys on portions of distribution systems outside business districts. The Oil Heat Task Force favored more frequent surveys on the ground that total reported leaks are high, and more frequent surveys would positively affect the environment by reducing methane emissions. However, EPA advised that preliminary results of a Gas Research Institute study commissioned under the Clean Air Act show that system-wide leak rates are low. AGA argued that the Oil Heat Task Force merely wants to increase the cost of gas to enlarge the market for oil.

NTSB asserted that 5 years is too long between checks for leaks on flammable gas systems in view of aging systems. The agency suggested RSPA study incident data to learn the correlation between leak rate and age, type of pipe, and other characteristics. NTSB then said leak survey frequency should be set according to these correlations. One other commenter also said leak survey frequency should be based on age, material, leak history, and soil characteristics.

AGA opposed the idea of an increased frequency, saying an increase is not likely to have a beneficial effect given the low leak rate from corrosion since 1984. AGA foresaw minimal benefits but a significant increase in costs.

The large majority of commenters on this issue opposed the increase, saying it is not justified and would not be cost beneficial. Numerous commenters said a minimum 5-year frequency is sufficient for cathodically protected steel pipe and plastic pipe, because these pipes experience relatively few leaks. Another commenter who opposed an increase argued that gas detectors eliminate the need for more surveys. Still another commenter noted that effective cathodic protection and odorization programs make more frequent surveys unnecessary. One commenter who expressed opposition said its existing leak survey and replacement program was satisfactory, while another commenter stated its opposition succinctly: expensive, impractical, and unnecessary.

One commenter who argued a minimum 3-year rate was unjustified noted that the KPL incidents involved old, customer-owned, unprotected lines that had been vegetation surveyed by meter readers. This commenter said the KPL evidence showed a need for gas detector surveys, but not more frequent surveys. More frequent surveys, this commenter said, should be tied to high leak rates, as from corrosion, deteriorating couplings, or construction defects. Another commenter similarly said that a frequency of more than 5 years should be based on need.

(2) The need to conduct leakage surveys at least annually on cathodically unprotected metallic distribution lines that lie outside business districts and on which electrical surveys are impractical.

The Oil Heat Task Force supported the notion of annual surveys on unprotected steel lines because of what the commenter considered a large number of leaks annually across the nation.

Three other commenters supported annual surveys to help combat the effects of corrosion on old unprotected lines and prevent multiple leaks from existing for up to 5 years between surveys. An additional commenter supported the increase because it surveys annually now.

One commenter supported annual surveys, but only in areas of high leakage.

Most who commented on the issue were opposed to the suggested increase in leak survey frequency, saying it lacked corresponding safety benefits. Many said it's too impractical to schedule more frequent surveys on unprotected parts of a system, since cathodic protection can vary by area or street. In some cases, these commenters said, unprotected services are randomly scattered over a city. The suggested increase would cause whole areas or systems to be surveyed annually without sufficient cause.

One commenter who saw no benefit said older systems are the source of corrosion leaks. These systems, the commenter said, have already been surveyed many times and possible areas of corrosion are protected or replaced.

Two other commenters who opposed the increase said there would be no corresponding benefits because corrosion incidents can occur shortly after a survey.

(3) How would such an increase (in survey frequency) affect the present costs of conducting leakage surveys on distribution lines in small and large systems?

About 15 commenters gave estimates ranging from $140,000 to $4 million a year per operator if the 5 year frequency were increased to 3 years. The range of estimated cost increases for surveying unprotected lines annually was from $66,000 to $19 million a year per operator. These estimates covered the costs of equipment, personnel, and training.

(4) [What] benefits would result from such rules. Information concerning accidents that operators might have avoided had they surveyed pipelines for leaks more frequently would be helpful.

Only a few commenters responded to this inquiry. None saw any benefit to increasing the survey frequencies. Some of the reasons were: Low corrosion accident rate; lack of corrosion accidents and system difference from KPL situation; know of no accidents that would have been avoided had survey been every 3 instead of every 5 years; most lines plastic, little likelihood of accident avoidance through increased leak survey frequency.

Conclusion

Based on our review of the information submitted, we have concluded that the number of accidents that might be prevented by surveying at the proposed increased frequencies is uncertain. In addition, the current safety data for the nation's population of gas distribution lines are not sufficient to determine if a correlation exists between leak rates and pipe age, material, or other characteristics. Also, state pipeline safety agencies commonly impose more frequent survey requirements on individual distribution lines that are found to pose an unusual risk. Under these circumstances and given the need to learn the effect of the final rule on leak rates, we are not at present considering any further amendment of the leak survey frequency rule.

Advisory Committee

As part of this rulemaking proceeding, RSPA obtained advice from the Technical Pipeline Safety Standards Committee (TPSSC) on the technical feasibility, reasonableness, and practicability of the proposed rule. The TPSSC is a statutory advisory committee comprised of 15 members, representing the natural gas industry, government, and the general public.

The TPSSC met in Washington, DC on March 11, 1992, and discussed the NPRM. The TPSSC voted for the proposed rule 10 to 1, with 1 member abstaining. A suggested revision concerning a typographical error in the text of the proposed rule has been corrected. The transcript and report of the meeting are available in the docket.

Rulemaking Analyses

E.O. 12866 and DOT Regulatory Policies and Procedures

RSPA has concluded that the amendment to § 192.723(b)(2) is not a significant rule under Executive Order 12866. Also, it is not a significant regulation under DOT Regulatory Policies and Procedures (44 FR 11034, February 26, 1979).

RSPA believes that the final rule will add minimally to the average compliance expense of the present rule. With respect to requiring the use of leak detectors, first, operators of gas distribution systems already have the equipment. They use portable gas detectors in business districts and to check enclosed spaces for gas leaks. Second, in leakage surveys outside business districts, most operators already use gas detectors for mains, because they generally lie beneath paved areas where vegetation surveys are inappropriate. Also, for service lines in these areas, many operators are voluntarily using gas detectors instead of vegetation surveys, and some State laws require operators subject to State jurisdiction to do so. Third, gas detector equipment is easy to use. Personnel that operators have trained to do vegetation surveys will need only slight, if any, additional training to use the equipment. Finally, although the survey process will take longer with leak detectors, any resulting additional costs will be mitigated by the period between surveys (maximum interval is 5 years) and the ability to conduct surveys with leak detectors any time of the year.

The benefits of requiring the use of leak detectors in leakage surveys are prevention of deaths, injuries, and property damage that might otherwise occur when hazardous gas leaks go undetected in residential neighborhoods. As an example of these potential benefits, the NPRM discussed the results of leak detector surveys in Kansas City, Missouri. Following a string of residential accidents in which four persons were killed and 16 were injured, with property damage exceeding $740,000, the local gas company conducted leakage surveys with leak detector equipment. Until then the company had relied on vegetation surveys by meter readers to discover previously undetected gas leaks. The leak detector surveys revealed a large number of previously undetected hazardous leaks. For instance, during one period, leak detector surveys revealed 2,156 leaks in 55,213 house service lines, of which the gas company considered 303 leaks to need immediate repair. Had these leak detector surveys been conducted earlier, many of the Kansas City accidents might have been prevented by timely repair of the leaking lines. The final rule should achieve similar benefits nationwide where operators are not using leak detector equipment to conduct leakage surveys.

With respect to surveys of certain unprotected metallic lines at 3-year intervals, the final rule will merely assure that when operators use leakage data to evaluate these lines for corrosion the data are not less timely than what § 192.465(e) intends for that purpose. RSPA did not attribute any additional compliance costs to this aspect of the final rule because the use of timely data is an inherent requirement of the existing § 192.465(e).

RSPA believes the final rule does not warrant a more detailed evaluation of its impact. The comments on the NPRM and the advice of the TPSSC are consistent with this view.

Regulatory Flexibility Act

Based on the facts available concerning the impact of this final rule, I certify under Section 605 of the Regulatory Flexibility Act that it will not have a significant economic impact on a substantial number of small entities.

E.O. 12612

RSPA has analyzed this final rule under the criteria of Executive Order 12612 (52 FR 41685; October 30, 1987). We find it does not warrant preparation of a Federalism Assessment.

List of Subjects in 49 CFR Part 192

Natural gas, Pipeline safety, Reporting and recordkeeping requirements.

In consideration of the foregoing, RSPA amends 49 CFR part 192 as follows:

PART 192—[AMENDED]

1. The authority citation for part 192 continues to read as follows:

Authority: 49 App. U.S.C. 1672 and 1804; 49 CFR 1.53.

2. In § 192.723(b)(1), the words "A gas detector survey" are removed and the words "A leakage survey with leak

detector equipment" are added in their place.

3. Section 192.723(b)(2) is revised to read as follows:

§ 192.723 Distribution systems: Leakage surveys and procedures.

* * * * *

(b) * * *

(2) A leakage survey with leak detector equipment must be conducted outside business districts as frequently as necessary, but at intervals not exceeding 5 years. However, for cathodically unprotected distribution lines subject to § 192.465(e) on which electrical surveys for corrosion are impractical, survey intervals may not exceed 3 years.

Issued in Washington, DC, on October 14, 1993.

Rose A. McMurray,

Acting Administrator for Research and Special Programs Administration.

[FR Doc. 93-25980 Filed 10-21-93; 8:45 am]

BILLING CODE 4910-60-P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 675

[Docket No. 921185-3021; ID 101893A]

Groundfish of the Bering Sea and Aleutian Islands Area

AGENCY: National Marine Fisheries Service (NMFS), National Oceanic and Atmospheric Administration (NOAA), Commerce.

ACTION: Modification of a closure.

SUMMARY: NMFS is rescinding the closure to directed fishing for Pacific ocean perch in the Aleutian Islands subarea (AI) of the Bering Sea and Aleutian Islands management area (BSAI). This action is necessary to fully utilize the total allowable catch (TAC) of Pacific ocean perch in this area.

EFFECTIVE DATE: 12 noon, Alaska local time (A.l.t.), October 22, 1993, until 12 midnight, A.l.t., December 31, 1993.

FOR FURTHER INFORMATION CONTACT: Andrew N. Smoker, Resource Management Specialist, NMFS, 907-586-7228.

SUPPLEMENTARY INFORMATION: The groundfish fishery in the BSAI exclusive economic zone is managed by the Secretary of Commerce according to the Fishery Management Plan for the Groundfish Fishery of the Bering Sea and Aleutian Islands Area (FMP) prepared by the North Pacific Fishery Management Council under authority of the Magnuson Fishery Conservation and Management Act. Fishing by U.S. vessels is governed by regulations implementing the FMP at 50 CFR parts 620 and 675.

In accordance with § 675.20(a)(7)(ii), the Pacific ocean perch TAC for the AI was established by the final 1993 initial specifications of groundfish (58 FR 8703, February 17, 1993) and later augmented from the reserve (58 FR 44136, August 19, 1993) to a total of 13,900 metric tons (mt). The directed fishery for Pacific ocean perch was closed on April 22, 1993 (58 FR 21951, April 26, 1993); the closure was rescinded on August 9, 1993 (58 FR 42031, August 6, 1993); and the fishery was again closed on August 19 (58 FR 44465, August 23, 1993). NMFS has determined that as of October 9, 1,575 mt remain unharvested.

The Regional Director, Alaska Region, NMFS, has determined that the 1993 TAC for Pacific ocean perch in the AI has not been reached. Therefore, NMFS is rescinding the August 19, 1993, closure and is re-opening directed fishing for Pacific ocean perch in the AI, effective at 12 noon, A.l.t., October 22, 1993, until 12 midnight, A.l.t., December 31, 1993.

Classification

This action is taken under § 675.20.

List of Subjects in 50 CFR Part 675

Fisheries, Recordkeeping and reporting requirements.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: October 19, 1993.

Richard H. Schaefer,

Director of Office of Fisheries Conservation and Management, National Marine Fisheries Service.

[FR Doc. 93-26077 Filed 10-21-93; 8:45 am]

BILLING CODE 3510-22-M