**BEFORE THE PUBLIC SERVICE COMMISSION
OF MARYLAND**

In the Matter of the Application of Washington Gas Light company for Authority to Increase Existing Rates and Charges and to Revise Its Terms and Conditions for Gas Service	* * * *	Case No. 9849

* * * * * * * * * * * *

PUBLIC DIRECT TESTIMONY

OF

DR. ASA S. HOPKINS

ON BEHALF OF THE OFFICE OF PEOPLE'S COUNSEL

MARCH 31, 2026

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, business address, and position.

A. My name is Asa S. Hopkins. My business address is 485 Massachusetts Ave., Suite 3, Cambridge, Massachusetts 02139. I am the Senior Vice President for Consulting at Synapse Energy Economics, Inc. ("Synapse"). Among other work, I provide extensive consulting regarding the future of gas utilities, and I also actively work in the related area of building decarbonization technology and policy.

Q. Please describe Synapse.

A. Synapse is a research and consulting firm specializing in energy industry regulation, planning, and analysis. Synapse works for a variety of clients, with an emphasis on consumer advocates, regulatory commissions, and environmental advocates.

Q. Please describe your professional experience before beginning your current position at Synapse.

A. Before joining Synapse in 2017, I was the Director of Energy Policy and Planning at the Vermont Public Service Department from 2011 to 2016. In that role, I was the director of regulated utility planning for the state's public advocate office, and the director of the state energy office. I served on the Board of Directors of the National Association of State Energy Officials. Prior to my work in Vermont, I was an AAAS Science and Technology Policy Fellow at the U.S. Department of Energy ("DOE"), where I worked in the Office of the Undersecretary for Science to develop the first DOE Quadrennial Technology Review. Prior to my time at the DOE, I was a postdoctoral fellow at Lawrence Berkeley National Laboratory, working on appliance energy efficiency standards. I earned my PhD and master's degrees in physics from the California Institute of Technology and my bachelor of science degree in

physics from Haverford College. My resume is included as Attachment ASH-1.

Q. Have you previously testified before the Maryland Public Service Commission?

A. Yes. I testified on behalf of the Maryland Office of People's Counsel in Baltimore Gas and Electric's rate case in Case No. 9692.

Q. Have you previously provided testimony in other jurisdictions on topics similar to those you are testifying on in this case?

A. Yes. I have testified on gas utility issues, as relates to capital decision-making, rates, and business risk in the District of Columbia, Quebec, Ontario, Maryland, Connecticut, Wisconsin, and New York. When I testified before the Régie de l'Energie in Quebec I was recognized as an expert in "energy transition in the gas industry, and business risk." The Ontario Energy Board qualified me as an expert on "the future of electric and gas utility regulatory and business models and associated business risk in the context of deep building decarbonization objectives."

I have also testified regarding benefit-cost analysis of utility capital expenditures in Vermont and Wisconsin. While there was no formal testimony, one of my responsibilities as the Director of Energy Policy and Planning for the State of Vermont was to provide regulatory input on benefit-cost and analysis and cost-effectiveness associated with energy sector policies, programs, and utility expenditures, such as energy efficiency and distributed energy resources. I also provided regulatory guidance to Vermont Gas Systems as it developed its integrated resource planning framework, which included use of economic tests to evaluate the benefits and costs of its potential capital investments.

Q. On whose behalf are you providing testimony in this case?

A. I am presenting testimony on behalf of the Maryland Office of People's Counsel.

Q. What is the purpose of your testimony in this proceeding?

A. Synapse has been retained by OPC to assist in the evaluation of the application of Washington Gas Light Company ("WGL" or "company") for authority to increase rates and charges for natural gas services. The purpose of my direct testimony is to review WGL's proposed additions to gas plant in service, with particular emphasis on WGL's replacement activities conducted under the rubric of the Strategic Infrastructure Development and Enhancement Plan ("STRIDE") program.

Q. How is your testimony organized?

A. After this introduction, my testimony continues in Section II with a summary of my conclusions and recommendations. In Section III, I discuss the history and principles of prudence review, including the importance of benefit-cost analysis to the prudence determination. Section IV continues foundational material with a review of the safety regulatory context for WGL, and Section V summarizes relevant information about safety incidents on WGL's system. Section VI summarizes the results of evaluating WGL's actions a framework for prudence review, grounded in the context provided in Sections III through V. The subsequent sections detail my evaluation of specific aspects of WGL's proposed plant additions: services selected based on expected leaks (Section VII), projects selected using the JANA risk model (Section VIII), project execution when costs change (Section IX), and evaluation of alternatives (Section X). Section XI contains my conclusions and recommendations.

Q. Are there any attachments to your testimony?

A. Yes. In addition to my resume, I have attached certain data responses from WGL that I relied upon while preparing my testimony. I have also attached a

paper by Burns *et al*. from the National Regulatory Research Institute ("NRRI") entitled *The Prudent Investment Test in the 1980s*, and a paper by Kiefner and Van Auker prepared for the Pipeline and Hazardous Materials Safety Administration ("PHMSA") entitled *Final Report on Repair/Replace Considerations for Pre-Regulation Pipelines*. I have also attached a frequently asked questions document published by Progressive Pipeline Management regarding pipe relining, and a summary of PHMSA-reported safety incidents on WGL's system. Finally, I have attached three quantitative analyses used when evaluating the cost-effectiveness of some of WGL's selected projects.

II. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. What conclusions do you draw in this case?

A. I find that:

- The large majority of WGL's estimated risk on its system is the aggregation of high-likelihood, low-consequence risks of leaks that are identified and repaired. Only about 3 percent of WGL's estimated risk corresponds to health, safety, or property damage from explosions or ignition events.

- Excavation and vehicle damage are the leading causes of PHMSA-reportable explosion and ignition events on WGL's system. Of the 19 gas-safety incidents on WGL's three-state system since January 1, 2016, 14 were caused by excavation, vehicle collision, or were otherwise directly human caused. Eleven of these 14 involved damage to plastic pipe (10 installed in 1995 or later), which WGL's risk analysis estimates has a higher likelihood of hazardous leak in excavation incidents than does older steel pipe.

- Replacement of a steel service with plastic provides little if any net benefit in reducing safety incidents. WGL proposes to add to plant in service more than $30 million from the replacement of vintage mechanically coupled

steel service lines with plastic based on the justification that those service lines would have some number of expected leaks per 100 services. But WGL failed to compare the costs and benefits of replacing service lines to reduce leak frequency. WGL had the information required to make such a comparison. If WGL had conducted a benefit-cost analysis, it would have found that it was not cost-effective to replace these service lines based on the value of avoided leaks.

- For STRIDE projects proposed, beginning with the 2024 project list, WGL has quantified risk in annual dollars using JANA. WGL could have compared these annual dollar values with the costs to mitigate the risk to determine whether the mitigation action is cost-effective. WGL has not made these comparisons for any of the capital additions it requests be added to plant in service in this case.

- WGL's JANA risk analysis overstates risk to Marylanders by including the consequence of reputational loss to WGL investors and by using the maximum consequence for each type of potential cost rather than the average cost. WGL failed to quantify risk in a way that can be compared with ratepayer costs.

- If WGL had used the cost information at its disposal (primarily related to the costs to address leaks) to compare project capital costs and expected risk-reduction benefits to Marylanders for its STRIDE projects analyzed using the JANA software and executed since the start of 2024, it would have found that all of the projects it was considering had costs that exceeded the benefits.

- WGL failed to revisit the decision to execute project decisions when costs increased, even when accurate cost information would have resulted in the project not being selected for prioritization.

- WGL failed to evaluate whether alternatives, such as relining and non-pipeline alternatives, could have reduced the cost of its risk-reduction activities.

- By failing to incorporate accurate information about the costs and benefits of pipe replacement and other alternatives into project selection, WGL has over-emphasized reduction in ongoing maintenance burden and under-emphasized reducing the risk of health, safety, and property damage. WGL has an obligation to operate a safe and reliable system; its decisions have misallocated resources away from fulfilling that obligation.

Q. What are your recommendations to the PSC based on these conclusions?

A. I recommend that the PSC:

- Find that WGL has not met its burden to show that its STRIDE distribution investments were prudently incurred.

- Find that WGL acted imprudently when it selected services for replacement based on the number of projected leaks per 100 services.

- Exclude investor-oriented benefits from benefit-cost analysis and require WGL to use its average consequence costs for common events.

- Find that WGL acted imprudently when it used a mis-calibrated JANA risk model to select STRIDE projects whose cost exceed their benefits.

- Disallow all $115.1 million of WGL's STRIDE distribution additions to rate base if WGL is unable to provide additional evidence to sufficiently support the prudence and cost-effectiveness of its project selection, and require refund of the STRIDE surcharge collected corresponding to these assets.

- In the event that the Commission declines to accept my recommendation to find that all of WGL's STRIDE distribution investments were imprudently

incurred, it should limit recovery for all main replacements to no more than the cost per foot of relining using a cured-in-place liner.

- Disallow or limit recovery for projects where WGL failed to evaluate feasible lower-cost alternatives, including non-pipeline alternatives.

III. PRUDENCE REVIEW IS ESSENTIAL FOR PROPER REGULATION OF A MONOPOLY UTILITY.

A. Prudence review exists to protect customers from utility spending decisions that lack the discipline of a competitive market.

Q. Could you please describe the role of prudence review in utility ratemaking?

A. Prudence review is the process by which regulators review utility investments and expenditures to provide the discipline on expenditures that the competitive marketplace would otherwise provide. Unlike a company in a competitive market, which competes with other firms to earn a profit, regulators provide utilities the opportunity to earn a particular return on their rate base. In a competitive market, if a company makes imprudent investments, it will earn a lower rate of return because competing firms that do not make that error will earn a greater market share, or the firm will otherwise have less revenue relative to its costs. In the regulated context, then, regulators must take steps to ensure that utilities prudently make plans and support their decisions, including potentially disallowing imprudent investments, to impose the same kind of discipline.

Q. Are there established principles about how to conduct prudence reviews?

A. Yes. *The Prudent Investment Test in the 1980s*, a research report by Burns, Poling, Whinihan, and Kelly of the National Regulatory Research Institute published in 1985, contains a clear and cogent summary of the underlying

philosophy and application of a prudence test for public utility investments.[1] Of particular interest here are two principles for prudence reviews:

- "[U]se the standard of reasonableness under the circumstances. That is, to be prudent, a utility decision must have been reasonable under the circumstances that were known or could have been known at the time the decision was made. A corollary to the standard of reasonableness under the circumstance is a proscription against the use of hindsight in determining prudence."[2]

- "[D]etermine prudence in a retrospective, factual inquiry. The evidence needs to be retrospective in that it must be concerned with the time at which the decision was made."[3]

Q. Do Burns et al. address whether a comparison of costs and benefits should be incorporated in a prudence review?

A. Yes. Burns *et al.* state that "[T]he concept of prudence protects the rights of individuals not in control of investment decision making. It does not require perfection in decision making but does require, for example, avoidance of deliberate exposure to substantial risk where the individuals not in control could suffer financially."[4] In effect, the prudently managed utility acts as its captive customers' agent. It must make decisions that it reasonably believes are in the interest of its customers. This includes evaluating whether the "individuals not in control [that is, customers] could suffer financially" by being forced to pay costs that exceed the benefits they receive.

[1] Attachment ASH-4.
[2] *Id.*
[3] *Id.*
[4] *Id.* at *iii-iv*.

Q. Is the competition WGL faces from electricity sufficient to provide the price discipline of a competitive market and thereby substitute for prudence review?

A. No. Because WGL is regulated as a cost-of-service utility, with rates set by the Commission, ongoing competition with electric utilities to provide energy service does not provide the price discipline that a competitive market would provide. Instead, the Commission must provide that discipline by reviewing utility actions for prudence and setting just and reasonable rates.

Q. Please describe your approach to prudence review in this proceeding.

A. In this proceeding, the relevant question before the Commission is whether WGL prudently used the information available to it to choose, continue, and execute the projects for which it now seeks recovery. WGL has an obligation to demonstrate that it has acted prudently for each investment, given that information. I have reviewed the available information to see whether it supports WGL's investment decisions. I reviewed the testimony that WGL's witnesses have filed, identified gaps in those filings, and requested information necessary to review a more complete picture of the information and analysis available to WGL at the time it made the investment decisions that led to the proposed additions to rate base in this case. Based on that information, I developed conclusions regarding whether project costs were prudently incurred based on the information available to WGL at the time it made each decision.

B. Prudence and cost-effectiveness go hand in hand

Q. What is the relationship between prudence and cost-effectiveness for a discretionary utility capital investment?

A. WGL is spending money on behalf of its customers, and its customers are being asked to pay back that cost, plus a return for WGL's investors and other carrying costs. Those customers should be getting sufficient benefit from that spending for it to be worthwhile. That means that capital investments should have benefits that exceed the costs in order to be determined to be prudent. If

this were a competitive market, rather than a monopoly, a company that spent on things that did not deliver net customer value would be outcompeted by a company that delivered that value. Regulators must provide this feedback in the case of a monopoly utility.

Q. What must a utility show, where reasonably possible, in order to demonstrate that a discretionary investment was prudent?

A. To the extent possible with available information, a utility must understand the benefits and costs of each of its expenditures, including to whom the benefits accrue. In some cases, there will not be sufficient information to make a quantitative comparison between costs and benefits. For example, it might not be possible to draw a direct line between new furniture in the utility's headquarters and quantified customer benefits, yet it could still be a prudent use of utility capital for the purposes of staff performance and retention. This type of consideration also arises in a company in a competitive marketplace; a regulator in this case would evaluate whether utility management has a reasonable expectation that the benefits will outweigh the costs. Where the company can quantify the costs and benefits, however, regulators should expect prudent management to seek accurate numbers and make the comparison.

For replacement projects aimed at reducing risk, project cost could include both direct project costs (the utility's capital investment, as passed through to customers) and indirect costs (such as customer costs from disruption during pipe replacement). Benefits would include the value of both the avoidance of future routine repair or replacement and the impact on the risk of an explosion or ignition event.

Q. Is a relative risk ranking, or a showing of relative risk reduction per dollar spent, sufficient to demonstrate that a replacement project was prudent?

A. No. A ranking-based method does not evaluate whether a project's benefits exceed its costs. Relative risk reduction per dollar spent also does not ensure prudent spending. Prioritized options are limited to the projects evaluated for risk per dollar spent, do not include all possible options the company could undertake to reduce risk, and do not account for the benefits and costs of choosing not to invest at all.

Q. In reviewing prudence, should the Commission consider whether the utility had alternatives—including lower-cost non-replacement options and no action—or is it enough for the utility to show that it selected a reasonable replacement method?

A. Considering alternative capital investments is important because replacements are expensive, long-lived investments that customers must pay for over many years with associated profits and carrying costs, and the utility is acting as the ratepayers' agent in selecting what to invest in. Thus, ratepayers count on the utility to make the best investment necessary to provide safe and reliable service. Consideration of alternatives is therefore central to the Commission's prudence review because it helps show whether the utility exercised reasonable judgment under the circumstances known at the time. Prudence review is not limited to checking whether money was spent efficiently after a decision has already been made. It also asks whether the utility made a reasonable choice among the available options before placing costs on customers. In the case of distribution pipe risk where there is no active leak, regular monitoring and leak detection surveys may be the only prudent option.

Alternatives analysis is especially important where the utility is not under a legal obligation to choose replacement. In that circumstance, the prudence question is not merely whether the utility executed a replacement project competently, but whether replacement was a reasonable choice in the first

place. If a comparable safety or reliability objective could have been achieved at lower cost, failing to examine that possibility is inconsistent with prudent management on behalf of ratepayers.

If the Commission does not examine whether lower-cost alternatives were available and reasonably considered, then customers may be required to pay for investments that were avoidable. In that sense, reviewing alternatives is one of the principal ways in which prudence review protects customers from unnecessary capital spending.

It is also not enough to show only that a replacement project was competently designed or efficiently executed. Otherwise, the utility has answered only the narrower question of how it chose to replace pipe, not the more important question of whether replacing that pipe was justified.

Q. Are there any assets for which WGL's tariffs have required cost-benefit analysis when determining how much is prudent to invest?

A. Yes. As WGL witness Kevin Murphy explained in response to Staff Data Request 8-9, according to the company's tariff,[5] "[n]ew customers are required to provide a contribution in aid of construction (CIAC) if the net present value of the expected revenues from the customer does not cover the cost to connect the new customer." That is, for this kind of discretionary investment, WGL has conducted a benefit-cost analysis and charges the new customer the amount required to make the analysis come out in favor of building the asset. Charging any less would be imprudent. I note here that I understand the Commission has recently decided to eliminate line extension allowances. This decision puts the prudence decision, and associated costs, entirely in the hands of the impacted customer. In making this decision, the Commission is incorporating the risk of

[5] *See* Washington Gas Light Company Tariff, General Service Provision #14.

unrecovered costs resulting from future reductions in gas use into its consideration of the benefit-cost calculation.

Q. Has the Commission previously required benefits to exceed costs for an investment to be deemed reasonable?

A. In Order No. 90948 of December 4, 2023, in Case No. 9692 (Baltimore Gas and Electric's application for a multi-year rate plan), the Commission in several areas used benefit-cost analysis to inform its rulings on whether to allow BGE to recover proposed expenditures in its multi-year plan rates:

- The Commission approved expenditures for BGE's program to proactively replace substation transformers (while limiting the budget of the program) based in part on the results of a risk-informed benefit-cost analysis.[6]

- For three new projects—proposed gas meter conversions,[7] a "blue sky" vegetation management program,[8] and a "resiliency enhancement" program[9]—the Commission rejected expenditures in part on the grounds that BGE had not conducted any benefit-cost analysis to determine whether customer benefits would exceed costs.

Q. Do regulators in other states require benefits to exceed costs as part of a prudence review?

A. Yes. State commissions have repeatedly required utilities to support discretionary investments with a showing that customer benefits justify customer costs. This is nationwide standard practice for utility investments in energy efficiency and other demand-side programs, as it is with the EmPOWER program in Maryland. Commissions have also expressly treated the absence of a benefit-cost analysis as a failure of proof on whether proposed

[6] Maryland PSC, Order No. 90948. December 4, 2023, at pages 94–95.
[7] *Id.* at 150.
[8] *Id.* at 118.
[9] *Id*. at 83-85.

investments are reasonable, prudent, or cost-effective. Some recent examples include:

- The Illinois Commerce Commission ("ICC") required a benefit-cost analysis for Commonwealth Edison's Grid Plan. The ICC ordered that "[t]he Company must develop an analytical approach that sets values for contributions toward the statutory goals …, both quantitative and qualitative, and identify types of investments where benefit-cost analysis ('BCA') frameworks (like those traditionally used in EE) will be appropriate. All Grid Plan investments should be evaluated in terms of their contribution toward achieving these goals and others consistent with the objectives and requirements of the Grid Plan statute. Until such an analysis is conducted, the Commission cannot determine whether or to what extent the Company's investments will be prudent and contribute to meeting the statutory goals. While the Commission recognizes initial cost-effectiveness analysis will improve over time, ComEd's current framework is not sufficiently developed to demonstrate compliance. Accordingly, the Commission is unable to reasonably assess the investments in terms of cost-effectiveness in furtherance of ComEd's statutory goals."[10]

- The Oregon PUC limited recovery of PacificCorp's investment in the Gateway South transmission line because "PacifiCorp has failed to provide sufficient analysis to justify its decision to construct the line sooner rather than later. We agree with Staff that a robust cost-benefit analysis is required to demonstrate benefits to Oregon customers starting on the rate effective date."[11]

[10] Illinois Commerce Commission, Order in cases 22-0486 and 23-0055, Dec. 14, 2023, at page 40.
[11] Public Utility Commission of Oregon. Order No. 24-447, entered Dec. 19, 2024, at page 42.

- The California Public Utilities Commission denied Pacific Gas & Electric's ("PG&E") forecasted expense for a billing system upgrade "based on a lack of basic information and benefits" and directed that PG&E would need to file, among other things, "[a] cost-benefit analysis for the project that considers whether the overall benefits of the project outweigh the overall costs."[12]

C. Absolute and relative cost-effectiveness are different.

Q. Could you please elaborate on what "cost-effective" means?

A. The term "cost-effective" can mean different things in different contexts. A critical consideration is whether the term is used in a relative manner or an absolute manner. "Relatively cost-effective" means that one option has a better relationship between its benefits and costs than other alternatives. "Absolutely cost-effective," however, means that the benefits exceed the costs. It is possible for an action to be relatively cost-effective yet not absolutely cost-effective (it is the best among bad options), and it is possible for an action to be absolutely cost-effective yet not relatively cost-effective (it is better than taking no action, yet other actions are even better).

Q. What kind of cost-effectiveness should regulators be looking for when evaluating prudence?

A. Regulators should be seeking both, but absolute cost-effectiveness should be the foundation for regulatory review. Utilities should make capital investments only when the benefits of irreversible action exceed the costs, and, if there are multiple options, should seek the action that produces the greatest net gain for ratepayers and residents. If a utility were in a competitive market for gas service and made investments that were not absolutely cost-effective, its competition would take advantage of its unnecessary costs and associated

[12] California Public Utilities Commission. *Assigned Commissioner's Scoping Memo and Ruling* in Application NO. 24-10-014, March 27, 2025, at pages 1–2.

higher rates to outcompete it for customers by offering a better cost-benefit proposition.

D. STRIDE preapproval does not excuse WGL from demonstrating that its actual investment decisions were reasonable when made.

Q. When a regulator or legislature provides some kind of pre-approval for spending, does that change the need for retrospective prudence review?

A. No. Pre-approval to spend or recover funds does not insulate a utility from a finding of imprudence. Utility management has an ongoing obligation each day to decide whether to continue with, expand, or restrict each investment. If information showing that a decision is imprudent becomes available to a utility, even after the decision has been approved by a regulator or legislature, utility management has an obligation to make a different, prudent choice.

Q. What is the relationship between WGL's pipe replacement activities and the STRIDE program?

A. WGL plans replacement activities under the umbrella of the STRIDE program. The STRIDE framework has allowed WGL, through a surcharge on customer bills, to begin financial cost recovery for capital invested in pipe replacement since the last rate case before the projects are evaluated in this rate case. Partial cost recovery under the STRIDE structure does not presume prudence for the underlying investments—those investments are reviewed for prudence in this case.[13]

[13] *See* Proposed Order of Public Utility Law Judge at 42, 43 n.150, ML# 305809 (Case No. 9708, Oct. 25, 2023) (affirmed by Order No. 90941); Md. Pub. Serv. Comm'n, Order No. 90099 at 10 n.36 (Case No. 9486, Mar. 2, 2022) (noting the distinction between the prudency review that occurs in a rate case when STRIDE assets are moved into rate base, and the initial reviews that occur throughout the STRIDE case itself).

E. In this proceeding, the Commission must determine whether WGL prudently used the information available to it to choose, continue, and execute the projects for which it now seeks recovery.

Q. What obligations does WGL have with respect to prudently deciding which assets to retire or replace?

A. As noted above, WGL is making financial decisions on behalf of "individuals not in control of investment decision making."[14] Thus, WGL should consider the impacts of available actions, as well as inaction, in each case, when making each investment decision. If the primary purpose of these investments is to lower safety risk, this implies that WGL has an obligation to understand the risk it is mitigating and select projects that make sense from a risk-reduction perspective, while accounting for cost.

IV. PHMSA REGULATORY COMPLIANCE REQUIRES RISK MANAGEMENT, NOT PIPE REPLACEMENT.

A. PHMSA's Distribution Integrity Management Program ("DIMP") rules require utilities to identify and manage risks. They do not require retirement or replacement of higher-risk materials at a specified pace or by a date certain.

Q. According to WGL, what are the stated purposes of WGL's investments to replace aging mains and services?

A. WGL has identified the top threats on its system as leaks from gasket or O-ring failures, corrosion leaks, excavation damage, and natural forces.[15] Witness Murphy states that WGL seeks to address vintage materials on its system that "PHMSA has identified as positing a heightened safety risk, and for which operators are required to have remedial plans in place."[16] WGL has selected replacement with plastic piping as the primary mechanism to address these system concerns.

[14] Burns et al., Attachment ASH-4, at *iii-iv*.
[15] *Id*. at page 15.
[16] Murphy Direct at page 27.

Q. Does PHMSA require any materials to be retired from service at a specific pace or by a certain date?

A. Federal pipeline safety requirements governing natural gas distribution systems do not mandate that utilities retire or replace higher-risk pipe materials at any specified rate or by any specified date. Rather, the federal regulatory framework established by PHMSA relies primarily on a risk-management approach under the DIMP rules.

PHMSA's DIMP regulations are codified in 49 C.F.R. Part 192, Subpart P (§§192.1001–192.1015). These rules were established in 2009 and require each gas distribution operator to develop and implement a written integrity management program designed to identify and reduce risks within its system. Among other requirements, operators must identify potential threats to their distribution infrastructure, evaluate and rank the risks associated with different segments of the system, and implement measures designed to address those risks. The regulations also require operators to monitor system performance and periodically evaluate the effectiveness of their integrity management programs.

In carrying out these responsibilities, operators must consider the risks associated with particular pipe materials. Certain materials used in older distribution systems—such as cast iron, wrought iron, bare steel, and some early plastic pipes—are widely recognized as presenting elevated risk in certain circumstances, particularly due to corrosion, brittleness, or other degradation mechanisms. PHMSA's regulations therefore require operators to evaluate these materials as part of their threat identification and risk-ranking processes.

However, the federal rules do not require that such materials be replaced or set a prescribed schedule for replacement. Instead, the DIMP framework requires operators to determine and implement appropriate risk-reduction measures

based on the conditions present within their systems. These measures may include a range of actions, such as enhanced leak detection, increased inspection frequency, improvements to corrosion control, pressure reductions, targeted repairs, or pipe replacement. The choice of mitigation measures is left to the operator's engineering judgment and risk evaluation, subject to oversight by state regulators.

Consistent with this risk-based framework, PHMSA has not established nationwide deadlines for the retirement or replacement of specific distribution pipe materials. Older materials such as cast iron or bare steel may continue to operate within distribution systems so long as the operator maintains them in compliance with applicable safety regulations and manages the associated risks appropriately. As a result, many gas distribution systems in the United States continue to contain segments of these legacy materials.

In addition to the DIMP requirements, PHMSA regulations impose a variety of ongoing safety obligations that apply to all distribution systems regardless of pipe material. These include requirements related to leak surveys, corrosion control for steel pipelines, maintenance of pipeline facilities, and prompt repair of hazardous leaks. Through these provisions, operators must monitor the condition and performance of their systems and take corrective actions when necessary to maintain safe operation.

In summary, the federal pipeline safety framework administered by PHMSA does not require gas distribution utilities to retire higher-risk pipe materials at any particular rate or by any specific date. Instead, federal regulations require operators to identify risks within their systems and implement appropriate measures to address those risks, which may—but need not necessarily—include pipe replacement. Decisions regarding the pace of system modernization or replacement programs are therefore generally shaped by

utility planning and state regulatory policy rather than by prescriptive federal mandates.

Q. What consequences of pipeline risk is PHMSA particularly concerned about?

A. PHMSA is particularly concerned about death, injury, property damage, and environmental damage. When PHMSA was developing the DIMP regulations, it explained its actions by saying: "To achieve a significant reduction in pipeline accidents, deaths, and injuries we must address distribution systems."[17]

Q. PHMSA encourages utilities to address specific materials, including cast iron and bare steel. Does it mandate that these materials be replaced?

A. No. DIMP requires utilities to understand the risks on their systems and take appropriate actions, including repair and replacement when warranted, to mitigate those risks.

B. When replacement is discretionary, prudence requires more than showing it was a permissible option.

Q. Is PHMSA's identification of replacement as a permissible way to reduce risk a sufficient justification for prudence?

A. No. Simply being allowed to take an action, as one of many allowed options, is not sufficient to demonstrate prudence. Replacement may be justified and prudent in cases where the utility can show that the benefits of replacement outweigh the costs, and other options to lower risk would not achieve comparable benefits relative to their costs. For example, in the case of an active Grade 1 leak where repair is not an available option, replacement is almost certain to pass that test. Grade 3 leaks, however, are not deemed to be hazardous to life or property and can safely be monitored. In this case, the risk is low enough, relative to the cost of repair or replacement, that risk reduction

[17] https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2025-08/DIMP-PilotInspectionFindingsAPGA-031011-1.pdf.

cannot justify the expense; this implies that benefit-cost analysis is the right framework for decision-making.

Q. In your view, what kinds of alternatives should a gas utility consider before undertaking full replacement of a main or service in order to be prudent?

A. At a minimum, a prudent utility should consider whether the relevant objective can be met through continued monitoring, leak survey activity, targeted repair, pressure management, or other mitigative actions short of full replacement. Here I am drawing upon the *Final Report on Repair/Replace Considerations for Pre-Regulation Pipelines* by Kiefner and Van Auker, prepared for PHMSA in 2015.[18] The Kiefner and Van Auker repair-versus-replace report expressly frames the decision in those terms and identifies mitigative responses that may avoid or delay replacement where integrity can be maintained through ongoing assessment and repair. In my view, the relevant principle is broader: before committing customers to full replacement, the utility should examine any reasonable option that could achieve the same safety or reliability objective at lower net cost.

Q. Is full replacement always required when a main or service is identified as relatively high risk under DIMP or other integrity management processes?

A. No. Identification of elevated risk does not itself require full replacement. The Kiefner and Van Auker report explains that "[r]eplacement is not necessary if it is feasible to continue to maintain the integrity of the pipeline, main, or service through on-going integrity assessments and mitigation of findings."[19] It further states that "[i]t is up to the operator to decide whether or not pipeline integrity can or will be preserved via the necessary maintenance and repairs or whether, instead, the pipeline, main, or service will be replaced."[20] That point

[18] Attachment ASH-5.
[19] Attachment ASH-5 at pdf page 5.
[20] *Id.*

is important here because WGL often treats replacement as the default response to higher-risk assets when other options are available. The repair-versus-replace report instead frames the issue as a management decision about whether integrity can be maintained through continued mitigation, not as an automatic replacement mandate. I would add that where the report says a decision is "up to the operator,"[21] the Commission retains authority to evaluate the prudence of the operator's decisions.

In addition, PHMSA noted that replacement is not necessary where continued mitigation is feasible. The report states that "[o]lder pipelines are not necessarily less safe than more modern pipelines. If their integrity can be maintained by appropriate and timely inspections followed by remedial responses to restore their serviceability, they can continue to operate without excessive risk to the public."[22] It also explains that the purpose of the report was to help operators "determine when replacement makes more sense than continuing to do the necessary repairs to maintain serviceability.[23]" The Executive Summary makes the same point in more explicit terms: "Replacement is not necessary if it is feasible to continue to maintain the integrity of the pipeline, main, or service through on-going integrity assessments and mitigation of findings."[24] That language strongly supports the conclusion that continued monitoring and repair can be a prudent alternative to replacement.

Q. According to the PHMSA-sponsored report, what types of actions can an operator take to avoid or delay replacement of a main or service?

A. The report identifies a broad category of "Mitigative Responses for Gas Distribution Systems."[25] This section of the report summarizes the history of

[21] *Id*.
[22] *Id*. at pdf page 17.
[23] *Id*.
[24] *Id*. at pdf page 5.
[25] *Id*. at pdf pages 96–104.

the development of the DIMP regulations, which reflect the fact that the diversity of gas distribution systems makes standard requirements impractical. Instead, DIMP requires a robust process of knowledge, threat identification, risk evaluation, risk mitigation, performance measurement and monitoring, process evaluation, and reporting. Some of the additional or accelerated actions that the report highlights include increased frequency of leak surveys and enhanced detection efforts, replacement (especially where soil or earth movement conditions are unfavorable), relining, addition of excess flow valves, and tracking material failures. The report also states that replacement may be deferred "if the rate of degradation is slow enough" and, specifically for distribution assets, "if there is a likelihood that the leakage rate will not increase with time."[26] That is consistent with a continued monitor-and-repair approach rather than immediate replacement.

Q. Does the PHMSA-sponsored report contemplate that an operator may continue to monitor leak trends, increase patrols or leak surveys, manage leaks, and repair specific defects rather than replace an entire segment?

A. Yes. That is the central logic of the report. It states that integrity can be maintained through "on-going integrity assessments and mitigation of findings,"[27] and that repairs made in response to integrity assessments "will be an effective means to achieve reductions in incidents."[28] The report further explains that the essential goal is to determine whether relevant threats "can be successfully mitigated via periodic integrity assessments via the 'repair' option."[29] The report also notes that, for natural gas distribution systems, the common assessment tools differ from transmission and hazardous liquid systems, and that "leak surveying is a more common method."[30] The report

[26] *Id*. at pdf page 7.
[27] *Id*. at pdf page 5.
[28] *Id*. at pdf page 26.
[29] *Id*.
[30] *Id*. at pdf page 32.

clearly contemplates continued monitoring, leak management, and targeted repair as alternatives to full replacement.

Q. What factors does the PHMSA-sponsored report indicate should inform the decision whether to continue monitoring and repair or instead proceed to replacement?

A. The report indicates that the decision depends on the nature of the threat, whether it is technically feasible to mitigate that threat, and the comparative cost of continued mitigation versus replacement. The Executive Summary states that "[r]eplacement becomes necessary whenever one or more of the 'driver' integrity threats cannot be mitigated and the risk of failures is not acceptably small" and that replacement "may become the best choice where addressing the threats and/or assuring safety is technically feasible but the cost of properly addressing the threat and/or assuring safety is more than the cost of replacement."[31]

The report is also clear that not all threats point toward replacement. It states that "[r]eplacement is not an appropriate means to deal with threats that tend to be random in nature or that affect only specific areas such as mechanical damage and outside forces. Replacing a pipeline, main, or service would be an inefficient reaction to such threats."[32] That is particularly relevant where actual reportable incidents are driven largely by excavation and outside-force damage rather than deterioration of older pipe materials.

Q. Why is the monitor-repair-replace framework particularly relevant where much of the modeled "risk" consists of routine leak response and repair rather than catastrophic events?

A. It is particularly relevant because the report expressly recognizes that repeated small leaks do not necessarily imply that replacement is the appropriate response. It states that "small leaks in a gas pipeline can be repaired and are

[31] *Id*. at pdf page 7.
[32] *Id*. at pdf page 6.

generally not hazardous to people, property, or the environment" and that "replacement of a gas pipeline that repeatedly developed small leaks might not be the most appropriate response."[33]

That point maps closely onto the issues in this case. Where much of the modeled "risk" reflects the expected cost of responding to routine leaks, rather than the expected cost of rare catastrophic events, the central prudence question is whether WGL showed that full replacement was more reasonable than continued monitoring and repair. The repair-versus-replace report supports the conclusion that this comparison should have been made explicitly.

Q. How does that guidance bear on the prudence of WGL's approach in this case?

A. It shows that replacement should not have been treated as the automatic or presumptive response to elevated risk. The repair-versus-replace report states that "pipeline replacement is rarely the most effective response to reducing pipeline incidents" and that "a replacement decision is likely to be considered if and only if threat management is not feasible by other means."[34] It also states that, "[i]n most cases repairs made in response to these integrity assessments will be an effective means to achieve reductions in incidents."[35]

This guidance confirms that WGL should have evaluated whether continued mitigation was feasible before committing customers to replacement. Where the relevant issue is largely a continuing maintenance burden, rather than a threat that cannot be mitigated through periodic assessment and repair, the report indicates that a repair option should be seriously evaluated before replacement is selected.

[33] *Id*. at pdf page 30.
[34] *Id*. at pdf page 26.
[35] *Id*.

V. EXCAVATION AND OUTSIDE-FORCE DAMAGE ARE THE PRIMARY CAUSES OF SERIOUS SAFETY INCIDENTS ON WGL'S SYSTEM.

Q. What have been the total real-world health, safety, and property-damage consequences of incidents related to hazardous leaks on WGL's system in recent years?

A. There have been 19 incidents on WGL's three-jurisdiction system since January 1, 2016, that rose to the level that they were reported to PHMSA. Of these, six happened in Maryland. Attachment ASH-8 summarizes these events based on WGL's reports to PHMSA. Of the 19 events, 11 were related to excavation or other direct damage to WGL's system from non-utility construction, and three were related to vehicle damage. The remaining five incidents were related to indoor mercury regulators, damage from a water leak, electric arcing from a nearby transformer and fence, a failed plastic joint, and a corroding copper service. In total, there have been seven fatalities and 37 injuries as a result of these incidents. All the deaths and most of the injuries were the result of a single event related to mercury regulators, not damage or leaks from mains or services. WGL reported estimated costs of $5.5 million as the cumulative costs to WGL, building owners, and others (not counting any monetized impacts of injuries or death).

Q. What strikes you about these incidents?

A. I am struck by the extent to which excavation and vehicle damage are the leading causes of PHMSA-reportable explosion and ignition events. I am also struck by the fact that of 14 events caused by either excavation or vehicle strike, 11 occurred on plastic pipe. The parameters in WGL's JANA analysis model indicate that steel pipe is better than plastic for withstanding excavation events without creating a hazardous leak. Given WGL's recent focus on replacing vintage mechanically coupled steel with plastic pipe, I am concerned that WGL is (by its own modeling) increasing the likelihood of an excavation-related explosion or ignition event in the name of risk reduction by replacing

steel assets rather than leaving them in place. Since excavation is the main source of real-world safety incidents on WGL's system, I am concerned that WGL is overly focused on reducing repair-related risk from typical system operations and not sufficiently focused on the risk that manifests in explosions and ignition events.

Q. Did witness Murphy make other troubling statements regarding the value of plastic pipe?

A. Yes. In response to OPC DR 10-5, witness Mr. Murphy stated that "[t]he likelihood of a leak on a new plastic main is one to two orders of magnitude less than that of piping targeted for replacement" and "[t]he likelihood of a leak on any given new plastic main segment is near zero, and this includes risk attributable to third party damage threats." These statements appear to be focused on the incidence of typical leaks, rather than with the prevalence of plastic pipe in PHMSA-reported safety incidents and WGL's own modeling using JANA, where excavation-related leak likelihood is greater for plastic than for steel.

Q. PHMSA's 2011 "call to action" urges the retirement or replacement of leak-prone pipe.[36] Shouldn't that be sufficient evidence that pipe replacement is necessary to improve safety?

A. PHMSA's voluntary call to action is grounded in correlation between older pipe (especially cast iron and bare steel, which is leakier than new pipe) and safety incidents. Correlation is not causation, however. WGL's incident data show that leaks without some kind of precipitating event (e.g., from a pipe breaking due to construction) have generally not caused safety incidents. The American Gas Association states, regarding national incident data, "[o]ver 82% of gas distribution incidents over the past 12 years have been due to time

[36] U.S. Department of Transportation. *Call to Action to Improve the Safety of the Nation's Energy Pipeline System*. November 1, 2011. Accessed at https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/docs/Action%20Plan%20Executive%20Version%201%20NOV%2011.pdf on March 23, 2026.

independent threats such as excavation damage and other outside force damage (such as vehicles hitting above ground assets, like meter sets)."[37] For WGL as well, the leading causes of incidents are third-party (excavation) damage and outside forces. These outside actions damage pipes, and pipe material plays a role in how susceptible the pipe is to different kinds of damage. Leak-prone pipes are not inherently "high risk." They are involved in a disproportionate number of incidents because of where they are, e.g., in denser urban areas, which have the most congested underground space (hence more likely to get hit by backhoes), have bigger frost heaves (due to asphalt trapping water and traffic), and are closer to water pipes (which break and undermine gas pipes). The risk is the location, not the pipe per se. Replacing pipe will not prevent the root cause problems. And replacing older metal with plastic may not change the outcome of a backhoe hit, frost heave, or water main break.

VI. WGL'S REPLACE-FIRST APPROACH TO RISK MANAGEMENT WAS IMPRUDENT, AND THE COMMISSION SHOULD DISALLOW THE COMPANY'S STRIDE COSTS.

Q. Have you evaluated WGL's approach to risk management on the basis of its grounding in risk to health, safety and property, its consideration of alternatives, and its use of cost-effectiveness analysis?

A. Yes, I have. Unfortunately, WGL's approach to risk management fails on all three fronts.

Q. How did WGL's risk framework for STRIDE investments fall short?

A. WGL fails to adequately distinguish between the risk associated with health, safety, and property-damage incidents and the risk associated with leaks. WGL's preemptive replacement-first approach is not designed to target assets that present higher-than-acceptable levels of risk to health and safety. The

[37] American Gas Association et al., *Comments on Pipeline Safety: Gas Pipeline Leak Detection and Repair*, page 54. Filed in Docket No. PHMSA-2021-0039 on August 16, 2023. Accessed at https://www.aga.org/wp-content/uploads/2024/08/2023-01_Alan-Chichester.pdf.

"risk" model WGL uses to select STRIDE projects is primarily a "leak" model, even though safety incidents on WGL's system have not been driven by leaks of the sort that replacement mitigates.

Q. How has WGL's consideration of alternatives fall short?

A. As I discuss in more detail in Section XI of this testimony, WGL failed to seriously consider or document its consideration of alternatives, such as non-pipeline alternatives and pipe relining, that could have reduced risk and leaks more cost-effectively than replacement.

Q. Does WGL describe its STRIDE investments as cost-effective?

A. Yes. Witness Murphy describes the $115.1 million of STRIDE distribution and $4.1 million of STRIDE transmission projects completed from January 1, 2023 to the end of the Test Year in this proceeding as "cost-effective replacements."[38] Witness Murphy also states that "the Company continuously analyzes cost-effective options to defer, reduce or eliminate the need to replace, upgrade, or construct new system components."[39] In response to OPC DR 13-1, Mr. Murphy states that, regarding STRIDE projects, "Cost effective refers to delivering value relative to the cost to obtain it."

Q. Does WGL use "cost-effective" in an absolute or a relative manner?

A. WGL uses it in a relative manner. When WGL says it seeks "cost-effective" investments, it simply means that the projects are managed to avoid waste and that the selected project approach is lower cost than other potential investments to address the same pipe segment.

[38] Witness Murphy Direct Testimony p. 35.
[39] Witness Murphy Direct Testimony, p. 20.

Q. Did WGL make an absolute comparison of the costs and benefits of replacement projects to decide whether to proceed with them?

A. No. WGL used risk-reduction benefits versus cost (i.e., "risk reduced per dollar spent" metric) as a ranking tool to decide how to spend this portion of its capital budget.[40] However, the company did not use this approach to decide whether to spend at all. WGL has not conducted a benefit-cost analysis of replacing targeted materials and facilities within the company's system that have been identified as higher risk on either a per-project basis or across all capital investments proposed for inclusion in this proceeding.[41]

Q. How did WGL select which projects to proceed with, if not based on a cost-effectiveness threshold?

A. WGL worked its way down a list of projects in order of risk reduction (as quantified by whatever metric it had available at the time) until it selected projects that aligned with its approved capital budget. "STRIDE projects are selected in rank order until sufficient work is identified to align with approved STRIDE expenditures."[42] Rather than letting the capital budget be determined by what investments would improve safety and cost for its customers, WGL determined its capital budget and then found projects to fill it. As WGL stated in response to OPC DR 6-3(f): "The aggregate capital budget is set before the full list of projects are submitted and reviewed."

Q. What conclusion do you draw from evaluating WGL's STRIDE investments against the framework you proposed?

A. I conclude that WGL has not shown it has a STRIDE distribution project-selection process that is focused on health and safety, that seriously considers alternatives, and that only proceeds with projects whose benefits exceed their costs. Therefore, I recommend that the Commission disallow WGL's STRIDE distribution costs. The following sections detail specific failings in WGL's

[40] Murphy Direct p. 14 lines 18-19, p. 15 lines 1-4.
[41] *See* WGL's response to OPC DR 1-1.
[42] *See* WGL's response to OPC DR 6-1(b).

project-selection and execution processes, which further support this finding and recommendation.

VII. WGL IMPRUDENTLY REPLACED MANY SERVICE LINES WITHOUT DEMONSTRATING THAT REPLACEMENT WAS JUSTIFIED.

A. WGL targeted certain services based on modeled leak frequency but leak frequency alone does not justify replacement.

Q. Which of WGL's investments are you addressing in this section?

A. I am addressing STRIDE investments for which WGL describes that the identified benefits take the form of some number of "projected leaks per 100 services." In Attachment 1 to its response to OPC DR 1-4, WGL confirmed that the "risk model" used to select these projects is a "leak/quad analysis" which witness Murphy explains in WGL's response to OPC DR 1-7. Exhibit KMM-02(b) lists 43 such projects, and I have extracted relevant information from that exhibit to Attachment ASH-9. These projects total $27,744,948 in gas plant in service, of which $24,075,694 is from Program 3 (vintage mechanically coupled main and services with affected services). Almost all these projects are labeled as "service-only" projects. Project names identify them as having been selected in 2022 or 2023.

Q. What does WGL mean by stating a project has a number of "projected leaks per 100 services"?

A. In WGL's response to OPC DR 1-7, Mr. Murphy states that this means that "WGL expects that the replaced assets would experience the number of projected leaks per 100 services over a period corresponding to the pipe's age from installation through 2019."

Q. When were these assets installed?

A. The assets targeted by Program 3 were installed between 1952 and 1956, or between 1962 and 1965. They are all at least 61 years old, and as much as 74 years old. The few projects that targeted copper or bare steel services likely

target older assets, given when those materials were generally used, and one project targeted pre-1975 plastic pipe (at least 51 years old).

Q. Can you translate "projected leaks per 100 services" into an annual likelihood of a leak on one service?

A. Yes, I can make a conservative estimate. To translate "projected leaks per 100 services" into annual leak likelihood on one service, I first divided WGL's estimate by the asset's age, to make it an annual value. For the purposes of this estimate, I assumed that the services have been in place for 60 years.[43] Then I divided by 100, to make a per-service value. This means that a single member of a group of services that has 45 "projected leaks per 100 services" would be expected to have 0.0075 leaks per year, or one leak every 133 years (on average). A group of 100 services would average one leak every 16 months.

Q. Has leak rate on service lines been related to reportable safety incidents on WGL's system?

A. No. As discussed in Section V above, safety incidents on WGL's system are overwhelmingly related to excavation and external-force damage. Only one of WGL's safety incidents in the last decade related to a spontaneously occurring leak on a service line: an event in February 2016 is attributed to corrosion on a copper service. Given the large fraction of incidents of this sort with plastic pipe, WGL knew even before it adopted JANA that replacement with plastic pipe does not provide substantial benefits in avoiding excavation or external-force-related incidents.

Q. What impact does replacing a steel service line with plastic have on excavation and external-force risk, according to WGL's JANA modeling?

A. First, I want to be clear that the projects I am examining in this section were selected before WGL adopted JANA. Therefore, the details of the JANA

[43] This results in a conservative estimate (tending to overstate the leak likelihood). Because this is shorter than the actual installed life of the assets in question, the denominator will be smaller, thus increasing the leak likelihood relative to an asset-specific calculation.

modeling cannot impact the prudence determination for these assets. However, the JANA model parametrization is consistent with what WGL would have seen on its own system: plastic does not provide a net safety benefit for these types of incidents. To the extent that material plays a role in risk associated with these types of events, according to WGL's JANA modeling, plastic pipe is **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** more likely than steel to have a leak from an excavation event or **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** less likely than steel to have a leak from an outside-force event, such as a vehicle strike.[44]

Q. Is replacing services that have the highest expected leak rate necessarily prudent?

A. No. Prioritizing replacement with plastic based on leak rate does not prioritize based on health and safety. Ordering services by leak rate will identify services whose expected maintenance burden is highest. Service replacements are not required, so WGL should have compared the maintenance burden (including the cost of leak response along with repair or replacement in the event of a leak) to the cost of replacement to determine if replacement was cost-effective.

B. WGL could have compared expected avoided maintenance costs to annualized replacement costs using available information.

Q. How could WGL have compared the maintenance burden to the cost of replacement to determine if replacement was cost-effective?

A. I have prepared an analysis using only data available to WGL at the time it proposed and decided to execute these projects.[45] Through my analysis, I calculated the expected annual maintenance burden for an average service in each project. To do this, I used the method described above to estimate the

[44] Calculated from the values in Table 12 (excavation) and Table 43 (outside force) in Attachment 1 to WGL's response to OPC DR 10-3.
[45] *See* Attachment *ASH-9*

number of leaks per service per year, and multiplied it by $5,500,[46] which is WGL's average cost to repair a leak, plus an adder of about $400 to allow for response costs.[47] This cost is an operations and maintenance ("O&M") expense, so it would be passed through to ratepayers without further taxes, profits, etc.

I also extracted WGL's estimated project cost (rather than the actual cost, since only the estimate would have been available to WGL at the time it made its decision) and divided that by the number of services to be addressed. I then annualized this capital cost into a revenue requirement. Exhibit DP-1, which calculates the revenue requirement from transitioning STRIDE investments into rate base for this proceeding, shows the ratio of annual revenue requirement to capital cost is 9.14 percent.[48] With the benefit (maintenance burden reduction) and cost (annualized replacement cost) in hand, I could then calculate a benefit-cost ratio.

For example, greatest number of projected leaks per 100 services among the projects WGL selected was 94.39, for BCA 304174. This translates to 0.0157 leaks per year per service. That means WGL's expected annual leak repair cost (or maintenance burden) for an average service in this project is $87 (0.0157 leaks per year times $5,500 per leak). WGL was also aware that its estimated average cost to replace a service in this project was $27,290. This translates to an annual replacement cost of $2,494 (9.14 percent of $27,290). The benefit cost ratio for this project is therefore $87 divided by $2,494, or 0.035—more than an order of magnitude below the threshold of 1.0 for cost-effectiveness.

[46] In its response to OPC DR 15-1(c), WGL reports that it resolved 2058 leaks in the test year. In OPC DR 15-4 WGL reports total repair costs of $10.5 million in the test year. This implies an average cost to repair of $5,102 per leak.

[47] This value is for the test year, not 2023, but WGL would have had a similar number at hand for 2023.

[48] To calculate this value, I divided the annual revenue requirement shown in the exhibit ($15,415,201) by the addition to plant in service ($168,621,419).

C. A benefit-cost comparison would have shown that many service replacements were not cost-effective, even after accounting for the limited effect on serious incident risk.

Q. What is the benefit-cost ratio of the most cost-effective service replacement project that WGL selected based on "projected leaks per 100 services"?

A. The STRIDE distribution project with BCA 304193 had a benefit-cost ratio of 0.064.

Q. You made several assumptions and estimates in calculating these values. Should that cause the Commission to discount the results of your analysis?

A. No. I would have to be off by a factor of more than 15 in either costs or benefits (or some combination) for the most cost-effective of WGL's selected projects to have benefits that exceed its costs. While I had to estimate the actual lifetime of the assets (60 years) and the carrying cost (9.14 percent), use average repair costs, and may not have captured the full details of the relationship between gas plant in service, capex, and cost of removal, none of these assumptions or estimates could make the results change by such a large factor. There is no escaping the conclusion that WGL replaced assets that had an annual maintenance burden of $44 per service and instead is asking ratepayers to pay $1,773 per year per service, for an average benefit-cost ratio of 0.02.

Q. How would the results change if you added in other benefits, such as reduced health and safety risk associated with these assets?

A. First, WGL has presented no evidence that it had or used any estimates of health and safety risk for these assets when making this decision. Therefore, I cannot use WGL's estimates as of the time of its decision to quantify this effect. However, WGL had access to the same information about PHMSA-reportable safety incidents that is available today, and which I have summarized earlier in this testimony. It should have known that replacing service lines with plastic would not have a large positive impact on the largest

drivers of safety risk on its mains and services, namely excavation and outside-force damage. It would not have been reasonable for WGL to assume that avoided health and safety risk would provide the value well in excess of $1,500 per service per year that would be required to make the benefits exceed the costs.

D. These costs were imprudently incurred, and the Commission should disallow them.

Q. What are your conclusions regarding the projects you have been discussing in this section?

A. These projects were imprudently selected. It was unnecessary for WGL to replace these service lines, but it did, despite having information showing that the costs far outweighed the benefits.

Q. What should the Commission do about this imprudence?

A. The Commission should disallow the inclusion of projects selected based on projected leak frequency, such as those listed in Attachment ASH-9. For the projects listed in Exhibit KMM-02(b), the total resulting gas plant in service reduction would be $27,744,948. Additional projects included in the small-project inventory summarized in Exhibit KMM-04 should also be disallowed unless WGL can show they were cost-effective. The Commission should also direct WGL to refund the portion of the STRIDE surcharge already collected corresponding to these projects.

VIII. JANA-ERA STRIDE PROJECTS WERE IMPRUDENT BECAUSE WGL SHOULD HAVE KNOWN THEIR COSTS EXCEEDED THEIR BENEFITS.

Q. When did WGL begin to use JANA to select pipes for replacement?

A. The company states that "implementation of JANA for distribution mains and services was complete as of 2023 and was used to identify mains and services projects that were included in the Company's 2024 STRIDE project list. In

2025, the Company's project list included both main and service as well as service-only projects that were informed by the JANA risk model."[49]

Q. What projects proposed for addition to rate base in this case did WGL use JANA to select?

A. Of the top 80 percent of STRIDE capital projects placed into service between January 1, 2023, and September 30, 2025, 24 projects totaling $18.3 million are informed by JANA model results.[50] These are mostly from "PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services" although there is some contribution from other programs as well.

Q. How did WGL use the JANA model to rank and select projects?

A. WGL estimated the risk-reduction benefits of STRIDE projects using JANA. Witness Murphy states "[r]esults from the JANA risk model, combined with non-specific per-unit cost estimates, allow the Company to prioritize assets as candidates for replacement by using a 'risk reduced per dollar spent' metric during its risk mitigation planning."[51]

The company states that the "cost for the BCA and the mitigatable risk for the BCA are considered when establishing the ranking according to mitigatable risk reduction per $10k of estimated project cost (RR/$) when considered for inclusion in an annual project list."[52]

WGL elaborates that "[t]he JANA bundles within the Project Year List are ranked in descending order by 'mitigatable risk per 10k' after elimination of the following: (i) bundles that were included in the prior year's list; (ii)

[49] *See* WGL's response to OPC DR 1-4(a).
[50] *See* WGL's response to OPC DR 1-4, Attachment 01.
[51] Murphy Direct at p. 14–15.
[52] *See* WGL' response to OPC DR 1-2(d).

service-only bundles that were combined and for which the 'mitigatable risk per $10k' was recalculated; and (iii) bundles that were not STRIDE eligible."[53]

Q. Could you please describe how the JANA software quantifies risk for each asset?

A. JANA defines total risk for each asset as a dollar amount equal to the likelihood of an event (expected number of events of different types, per year on that asset) multiplied by the consequence value of the events by type (represented in dollars).[54] In effect, the risk value for a given asset is the expected value of the cost that asset imposes by existing and being used in one year.

JANA's Likelihood of Failure model forecasts the number of leaks that may occur on each pipeline asset in WGL's distribution system for each threat category defined by PHMSA. JANA's Scenario Probability model calculates the probabilities of different leak outcomes for each threat category (e.g., the chance that a Grade 1 leak caused by corrosion leads to an explosion or ignition event).[55]

Furthermore, "the model evaluates the likelihood of an individual pipe segment failing, the scenarios that may occur due to a failure (e.g., a Grade 1, 2, or 3 leak), and the potential consequences associated with those scenarios (health and safety implications, property damage, repair costs, and others)."[56] More broadly, the model evaluates the likelihood of individual pipe segment failure, the scenarios that may result, and the associated consequences, including health and safety, property damage, and repair costs. WGL quantifies consequence values across five categories: (i) health and safety; (ii) direct

[53] *See* WGL' response to OPC DR 1-3(a).
[54] *See* WGL's response to OPC DR 1-12, OPC DR 1-13.
[55] *See* WGL's response to OPC DR 1-8(c).
[56] *See* WGL's response to OPC DR 1-9(f).

economic loss; (iii) regulatory impacts; (iv) environmental impacts; and (v) corporate image or reputation.

Q. How does WGL's JANA implementation determine the likelihood of events?

A. Attachment 1 to WGL's response to OPC DR 10-3 provides JANA's detailed explanation of its likelihood model. That document states that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Q. How did WGL calibrate the likelihood values used in its JANA model ?

A. Attachment 1 of WGL's response to OPC DR 10-3 states that **[BEGIN CONFIDENTIAL]** [redacted]

[57] *See* WGL's response to OPC DR 10-3, Attachment 01 CONFIDENTIAL at p. 4.
[58] *See* WGL's response to OPC DR 10-3, Attachment 01 CONFIDENTIAL at p. 5.
[59] *See* WGL's response to OPC DR 10-3, Attachment 01 CONFIDENTIAL at p. 6.
[60] *See* WGL's response to OPC DR 1-10, Attachment 01 CONFIDENTIAL at p. 10.
[61] *See* WGL's response to OPC DR 1-10, Attachment 01 CONFIDENTIAL at p. 13.

[redacted] [END CONFIDENTIAL]

Q. How does WGL's implementation of the JANA model quantify the consequences of events?

A. The JANA model quantifies the costs of several types of consequences associated with each potential failure scenario: health and safety, direct economic loss, regulatory impacts, environmental impacts, and corporate image or reputation. OPC DR 1-9 Attachment 01 includes some further details:

[BEGIN CONFIDENTIAL] [redacted] **[END CONFIDENTIAL]**

Q. How did WGL calibrate the cost it assigned to each type of consequence?

A. WGL states that the "parameters for the JANA probabilistic risk model were developed through Company Subject Matter Expert (SME) workshops,

[62] *See* WGL's response to OPC DR 10-3, Attachment 01 CONFIDENTIAL at p. 7.
[63] *See* WGL's response to OPC DR 1-9, Attachment 01 CONFIDENTIAL at p. 4.
[64] *See* WGL's response to OPC DR 1-9, Attachment 01 CONFIDENTIA at p. 4.
[65] *See* WGL's response to OPC DR 1-9, Attachment 01 CONFIDENTIAL at p. 2.

reviewing available Company data, and validated final parameter results."[66] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** WGL noted in its response to OPC DR 1-10(a) that the parameters for the consequence values were developed through internal Subject Matter Expert (SME) workshops in which at least 30 individuals (based on 30 unique job titles) throughout WGL's organization participated.[68] When asked to provide all presentations, documentation, analyses, workpapers, notes, meeting summaries, decision documents, or other materials used as part of the process that WGL used to determine these parameters, WGL provided only summary documents that offer "general insight into the process for selecting consequence parameters."[69] I am concerned that WGL did not retain any other relevant supporting information, inputs, analyses, or workpapers prepared for or resulting from these SME workshops, which required the input of dozens of experts and are key to its argument that tens of millions of dollars of investments were selected prudently.

Q. Could WGL have determined whether a proposed project's benefits exceeded its cost using information already available to it from JANA?

A. Yes. WGL had annualized risk-reduction estimates for each placement project. It also had per-project capital costs estimates, which it used for the relative ranking exercise. A prudent manager would have taken the additional and straightforward step of converting each project's capital cost into an annualized cost using standard regulatory finance methods and then comparing that cost against the annualized risk-reduction benefit. Doing so would have revealed

[66] *See* WGL's response to OPC DR 1-10(a).
[67] *See* WGL's response to OPC DR 1-10, Attachment 02 CONFIDENTIAL at p. 8.
[68] *See* WGL's supplemental attachment to its response to OPC DR 1-10(c).
[69] *See* WGL's response to OPC DR 1-10(b).

whether a project was absolutely cost-effective rather than merely ranked higher than other candidates on a relative basis.

A. WGL improperly treated investor benefits as if they were relevant for prudence evaluation

Q. What is WGL's total system risk as estimated by JANA as of the end of the test year?

A. According to WGL's JANA modeling, total annualized risk on WGL's Maryland system is $454,835,722 per year.[70]

Q. How is WGL's estimated system risk distributed across consequence categories?

A. The breakdown by consequence category is as follows:

- health and safety: $4,765,275 (1%);
- direct economic loss: $128,163,044 (28%);
- regulatory impacts: $146,189,127 (32%);
- environmental impacts: $19,441,643 (4%); and
- corporate image or reputation: $156,276,632 (34%).

WGL used the full aggregate risk figure – incorporating all five categories – when ranking projects by risk reduction per $10,000 of project cost.

Q. What are the components of "corporate image or reputation"?

A. Attachment 1 to WGL's response to OPC DR 1-9 (contained in Attachment ASH-3) breaks that category down into **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. The document also refers to these costs

[70] *See* WGL's response to OPC DR 1-13(c).

variously as **[BEGIN CONFIDENTIAL]** [redacted] [redacted] **[END CONFIDENTIAL]**

Q. How would WGL's corporate image or reputation be affected by leaks or incidents on WGL's system?

A. WGL has provided no information to explain or substantiate the link between leaks and safety incidents and its corporate image or reputation. These costs may reflect a negative public perception of WGL resulting from rising gas rates driven by WGL's high level of spending on the STRIDE program.

Q. How did WGL quantify these impacts?

A. WGL was unable to provide any information regarding how it derived or developed these values. WGL states that the consequence "values are generally derived by a review of historic natural gas incidents reported to PHMSA and the consequences associated with those incidents."[71] Corporate image and reputation costs are not reported to PHMSA, so I have no idea how WGL would have derived these costs. WGL estimates that a Grade 1 leak in a location typical of its Maryland service territory causes a reputation cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Reputation impact from an explosion or ignition event could be as large as **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. Are Maryland ratepayers responsible for supporting WGL's corporate image or reputation?

A. No. The consequences of leaks, explosions, or ignitions for WGL's public image, stock price, or reputation are not ratepayers' responsibility. These are the responsibility of WGL's investors. It is inappropriate and imprudent of WGL to select investments that the company expects ratepayers to pay for,

[71] *See* WGL's response to OPC DR 12-1.

based on whichever will have the greatest impact on mitigating risk to WGL's reputation or public image.

Q. Should WGL have known what risk-reduction benefits were reasonable to include in its JANA analysis for project selection?

A. Yes. It should have known that investor impacts, such as reputational impacts, were not reasonable to include, because those do not accrue to customers or Maryland residents. Thus, the Commission should disallow the use of reputation costs as a project-selection criterion.

B. WGL improperly inflated expected consequences.

Q. Did WGL characterize the impacts of safety incidents and leaks based on the average cost to address each scenario?

A. WGL's JANA documentation states that it used the maximum cost per incident. Attachment 1 to WGL's response to OPC DR 1-9 states that **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** However, WGL provided a clarification in response to OPC DR 11-3, stating that "[t]he Company discussed this section with the JANA Corporation for further clarification. The Company understands the values are averages that represent discrete, expected loss based on a statistical analysis of historical industry incident data. They do not represent maximum costs or historic worst-case scenarios." WGL further stated that the parameters "are only intended to provide a general magnitude of the different consequences that may occur due to a failure in the distribution system."

Q. Is it reasonable for WGL to use "a general magnitude" of costs from leaks when making investment decisions?

A. No. WGL should have used real averages of its own costs, at least for routine events like Grade 1, 2, and 3 leaks that occur hundreds of times per year. By

using "a general magnitude" for the costs of routine events, WGL risked inflating or otherwise misstating the modeled risk on its system, and thereby biased the characterization of risk (and thus project selection) toward routine events, rather than the safety-related events that should be the focus of its investments. WGL is obliged by PHMSA to understand the risks on its system—not simply "a general magnitude" of those risks.[72]

Q. Should WGL have reasonably known that its estimates of direct economic costs for leaks were overstated?

A. Yes. For example, WGL's Maryland system experiences about 2,050 leaks per year, of which about 1,500 are Grade 1 hazardous leaks. Its total costs to address these leaks must be less than the combined expenditures on mains and services operations (responding to leaks), mains and services maintenance (repairing leaks), and pipe replacement triggered by leaks. I have gathered illustrative values for these costs from WGL's filings in this case; WGL clearly had equivalent data when it made project decisions. Mains and services operations in the test year totaled about $0.53 million.[73] Mains and services maintenance in the test year totaled about $17.46 million, and WGL estimates around $10.5 million of this related to leaks.[74] Since the last rate case, WGL has invested about $46.2 million over 33 months in replacements triggered by leaks, or about $16.8 million per year.[75] Therefore, in total, the direct economic costs that WGL incurs to address leaks on its Maryland system are no more

[72] 49 CFR 192.1007(c) states: "An operator must evaluate the risks associated with its distribution pipeline. In this evaluation, the operator must determine the relative importance of each threat and estimate and rank the risks posed to its pipeline. This evaluation must consider each applicable current and potential threat, the likelihood of failure associated with each threat, and the potential consequences of such a failure."

[73] Exhibit PTN-6, Adjustment No. 29, Sum of Mains and Services in Operation Expenses on page 6 of 9.

[74] Exhibit PTN-6, Adjustment No. 29, Sum of Mains and Services in Maintenance Expenses on page 8 of 9. OPC DR 15-4.

[75] Murphy Direct, page 40, lines 1–3.

than about $27.8 million per year ($0.53 million + $10.5 million + $16.8 million).

Next WGL could have calculated its risk estimates for the annual costs for addressing leaks. Using the response cost values in the JANA model, and assuming leaks are evenly spread across services and miles of main, across all location categories, a typical year with 1,500 Grade 1 leaks and 550 Grade 2 or Grade 3 leaks[76] would produce an estimated response cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**—much higher than WGL's actual response costs—and, in fact, much higher than WGL's total leak-related costs. Add in roughly $15,000 for either repairing each leak or replacing the relevant section of pipe,[77] and total estimated direct economic costs for annual leaks according to WGL's use of the JANA model would exceed **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**—well over double WGL's actual annual direct costs to address leaks. WGL could, and should, have made this or a similar comparison to identify that the risk values it was using for project selection were faulty.

Q. Should WGL have corrected its risk-modeling parameters, such as the cost to respond to leaks?

A. Yes. Given the information at WGL's disposal, the company should have known that its model parameters for leak response were very different from its actual costs. Once WGL knew this, it would have been prudent for WGL to update the parameters in its risk modeling to help it select potential projects.

[76] In 2023 WGL's Maryland system had 1,433 Grade 1 leaks and 616 Grade 2 and 3 leaks. In 2024, WGL's Maryland system had 1,540 Grade 1 leaks and 563 Grade 2 and 3 leaks. (OPC DR 2-19 Attachment 1).

[77] Based on WGL's estimate in the JANA model of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per leak for Maryland repairs, **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per leak for service line replacements < 2" in diameter, and **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per foot for mains replacements (where $15,000 would buy about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** of replacement). [Attachment 1 to WGL's response to OPC DR 1-9].

Q. Should WGL have reasonably known that its estimates of regulatory costs for leaks were overstated?

A. Yes. While WGL has not detailed what kinds of costs are reflected in the regulatory costs calculation, it is reasonable to assume these costs include the costs for WGL and regulatory agencies related to events on WGL's system. WGL assumes that each Grade 1 leak in a location category 5 or higher (most of the Maryland system) incurs a regulatory cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**, falling to **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** per leak for the rest of the Maryland system, and each Grade 2 or 3 leak incurs a regulatory cost of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Given the number of Grade 1, 2, and 3 leaks on WGL's Maryland system in a typical year, this implies that about **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**[78] of WGL's estimated system risk reflects regulatory costs for leaks. This is a nonsensically large number when compared with the Maryland PSC's total FY2024 regulatory budget of $23.7 million, which covers far more than WGL's leak-related costs.[79] For further context, this figure dwarfs the combined costs of WGL's regulatory proceedings, WGL's reporting time (estimated by PHMSA at only 21.5 hours total of staff time across all leaks[80]),and the expenses PHMSA incurs to process leak data—which represents only a small fraction of PHMSA's $27.8 million pipeline safety IT budget. [81] WGL could, and should, have made this or a similar

[78] Calculated by summing the regulatory cost of leaks of each Grade and in each location category assuming leaks per asset (per service or per mile of main) are equally represented in all location categories. If WGL's system concentrates non-plastic assets in denser areas, as I would expect it does, this value is an underestimate.

[79] Maryland Public Service Commission. *2024 Annual Report* at page 119. Accessed at https://www.pscmaryland.com/wp-content/uploads/2025/11/MD-PSC-2024-Annual-Report.pdf on March 23, 2026.

[80] PHMSA estimates that filing the required annual reports on leaks takes 21.5 hours of staff time. *Pipeline Safety: Information Collection Activities*, 87 Fed. Reg. 65642 (Oct. 31, 2022) (Pipeline and Hazardous Materials Safety Administration, Department of Transportation).

[81] PHMSA's total Pipeline Safety IT budget for 2024, including all utilities and pipeline types in the country, was $27.793 million. Pipeline and Hazardous Materials Safety Administration.

comparison to identify that the risk values it was using for project selection were faulty.

Q. Should WGL have corrected its estimates of regulatory costs attributable to leaks?

A. Yes. WGL could and should have known that its model parameters for regulatory costs associated with leaks were unreasonably high. Once WGL knew this, it would have been prudent for WGL to update the parameters in its risk modeling to help it select potential projects that were cost-effective.

Q. Is there any evidence that WGL knew its parameters were wrong or took actions to correct its modeling values?

A. No. WGL has presented no evidence that it conducted suitable quality control on its risk estimation processes.

C. A reasonable cost-effectiveness threshold follows directly from WGL's own calculations.

Q. What metric did WGL use for project selection?

A. WGL used the mitigable-risk metric from JANA, combined with its cost estimate for each project. Mitigable risk is the difference between the modeled risk before and after the project (generally, before and after the assets are replaced with plastic pipe). WGL ranked projects by mitigable risk per $10,000 of project cost. It then used the ranking to proposed and conducted projects from the top of the list, working down.

Budget Estimates Fiscal Year 2026. Page 75. Accessed at https://www.transportation.gov/sites/dot.gov/files/2025-05/PHMSA_FY_2026_Budget_Estimates_CJ.pdf.

Q. WGL states that "[t]he risk model, and the parameters within it, are not suited for use in any context outside of integrity management."[82] Do you believe the risk model and its parameters can be used for benefit-cost analysis?

A. Yes. The benefit-cost analysis I am discussing is an integral part of integrity management, and the model could be suitable for processing the necessary likelihood and consequence data to conduct benefit-cost analysis if it were well calibrated to the actual state of WGL's system.

Q. Did WGL use its calculation of risk reduction per $10,000 to screen projects in or out of consideration?

A. No. WGL used this ratio only to prioritize projects for inclusion in its annual plans, not to decide whether a given project was cost-effective to pursue.

Q. Is risk reduction per $10,000 a useful metric to use when conducting a benefit-cost analysis of options to address an aging pipe?

A. Yes. That fraction is a dimensionless (dollars divided by dollars) ratio of benefits to costs. The only thing preventing this fraction from being a pure benefit-cost ratio is that the numerator is an annual benefit while the denominator is an upfront (lifetime) cost. WGL could annualize the cost using standard utility finance and this would become a standard benefit-cost ratio.

Q. Have you estimated what the threshold for risk reduction per $10,000 would need to be for the benefits to exceed the costs?

A. Yes. I used WGL's STRIDE revenue-requirement calculations to estimate the carrying cost for pipe-replacement investments. As I previously mentioned, Exhibit DP-1, which calculates the revenue requirement from transitioning STRIDE investments into rate base for this proceeding, shows the relevant ratio is 9.14 percent. This means that the annualized cost of $10,000 of project capital cost would be $914 per year. It also means that any project which has a risk reduction of greater than $914 per year per $10,000 would have benefits

[82] *See* WGL's response to OPC DR 11-5.

that exceed its costs. Any project that provides risk reduction of less than $914 per year per $10,000 in project cost would not be justified and thus should be presumed to be imprudently selected.

D. WGL's JANA-selected projects are not cost-effective, once modeling errors are corrected.

Q. Have you reviewed WGL's values for the claimed risk reduction per $10,000?

A. Yes. WGL provided these values for 2024 and 2025 projects in response to OPC DR 1-6 (included in Attachment ASH-3).

Q. Did these projects meet the $914 per $10,000 threshold you propose?

A. On the surface, yes, but WGL included investor benefits and overestimated leak-related consequences in its risk estimates—both errors that WGL should have caught if it were prudently evaluating its model. If WGL's models were corrected to address these errors, then none of WGL's 2024 and 2025 STRIDE projects would meet the cost-effectiveness threshold.

Q. How did you correct WGL's risk-reduction estimates?

A. WGL's consequence calculations were so far from reality that I had to start almost from scratch, although I did choose to use WGL's estimates of the consequences of explosions or ignition incidents due to the lack of other sources of information. My corrections address four consequence categories: safety risk, maintenance burden, regulatory costs, and environmental costs.

1) Regarding safety risk Witness Murphy confirmed that the JANA Lighthouse model is not able to separate the aggregate risk based on explosion, ignition, or leak type.[83] Thus, in order to estimate safety risk, I needed to create my own estimate. I began by working from WGL's system-wide health impact estimate. I used this starting value to estimate how much direct economic cost,

[83] *See*, for example, WGL's response to OPC DR 11-1(b).

regulatory cost, and environmental cost would be associated with explosions and ignitions. I calculated the weighted average ratio of these costs to the health cost for explosions and ignitions in each location category; for weightings, I used a combination of WGL's system geography (from WGL's response to OPC DR 11-2(c)), the distribution of WGL's leaks between mains and services (from WGL's response to Staff DR 8-21), and the locational difference in likelihood for excavation and outside-force damage (derived from Attachment 1 to WGL's response to OPC DR 1-9). The result is that I estimated how much total system risk (excluding corporate reputational risk) is associated with explosions and ignition events. I will refer to this combined risk as WGL's "safety risk," and it totals about $13.1 million per year, or about 3 percent of WGL's total system risk.

2) When analyzing maintenance burden I used the values for leak counts and costs that WGL provided in response to OPC Data Requests 15-1 and 15-4 to calculate direct annual economic costs for response, repair, and replacement. Annual leak-response costs were about $0.53 million[84] and annual leak-repair costs were about $10.5 million.[85] WGL estimates that it executed about 141 replacements resulting from leaks in the test year.[86] To estimate the cost per leak-driven replacement, I drew upon the average cost per service line for WGL's project M-34, which addressed 3,537 services at a total capital expenditure of $46.2 million, for an average of about $13,000 per service. To allow for potentially greater costs replacing leaking mains, I doubled this average and applied it to the 141 leak-based replacements, for an annual total cost of $3.7 million. In total, the response, repair, and replacement burden associated with the roughly 2,050 leaks that occur on WGL's system each year

[84] I assumed annual leak-response costs were equal to WGL's mains and services operations cost. Exhibit PTN-6, Adjustment No. 29, Sum of Mains and Services in Operation Expenses on page 6 of 9.
[85] *See* WGL's response to OPC DR 15-4.
[86] *See* WGL's response to OPC DR 15-1(d).

total about $14.7 million. This is about one-eighth of the maintenance-burden portion of WGL's estimated "direct economic cost" contribution to system risk. I therefore reduced WGL's estimate of this portion of the risk by a factor of eight.

3) For regulatory costs I assumed that WGL overestimated regulatory costs for routine leaks by a factor of 100, to bring the total burden of WGL's system down into a range that is plausibly commensurate with the burdens placed on the Maryland PSC and PHMSA. WGL's own regulatory burden for leak reporting would be covered in its O&M budget, and I estimate it to be limited to less than $100 per leak (which is still more than $200,000 per year).

4) For environmental costs I estimated environmental costs by translating the value of lost commodity from WGL's consequence calculations into the mass of emitted gas (assuming a gas value of $4 per MMBtu), then valuing it at $3,000 per metric ton (an approximate value for future emission-reduction value from federal "social cost of methane" estimates associated with reducing climate change).[87] The result was an estimate that the environmental cost is about 14 times the value of the lost commodity resulting in a reduction in estimated environmental consequences from leaks by about a factor of 25 compared with WGL's value.

Putting safety, maintenance burden, and environmental costs together, I find that WGL's corrected annual risk is in the vicinity of $30 million per year, rather than the roughly $455 million that WGL estimates. Just under half of the

[87] See, for example, U.S. EPA. *Supplementary Material for the Regulatory Impact Analysis for the Final Rulemaking, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" EPA Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances*. Page 154. Accessed at https://www.epa.gov/system/files/documents/2023-12/epa_scghg_2023_report_final.pdf on March 24, 2026.

adjusted risk on WGL's system is related to explosions and ignition events, rather than the 3 percent that WGL estimated.

For each project WGL selected using JANA, I used overall scaling factors to reduce each component of WGL's risk-reduction estimates.[88] I present these results in Attachment ASH-10. The risk reduction per $10,000 invested for these projects ranges between $163 and $366. The most cost-effective of these projects is a factor of 2.5 below the threshold to be absolutely cost-effective.

I think using overall scaling factors is reasonable for two reasons: First, a large portion of the risk comes from a small number of parameters, and I have estimated the impact of changing those parameters. Second, the resulting gap (of a factor of 2.5 or greater) between the risk reduction per $10,000 of WGL's projects and the $914 per $10,000 threshold for cost-effectiveness gives me confidence that project-level details are unlikely to push any project close to the threshold where benefits exceed costs. If WGL can provide project-specific risk analysis showing that it knew the benefits exceeded the costs I would welcome the chance to review this new information.

Q. What are the results of your benefit-cost calculations for the JANA-selected projects that WGL is seeking to add to rate base?

A. None of these projects are absolutely cost-effective (meaning their benefits exceed their costs) compared with the status quo of monitoring, combined with repair or replacement in the event of a leak.

[88] I assumed that the allocation of risk across consequence types was the same across all projects, based on the approximate proportionality of the consequence values for different types of events provided in Attachment 1 to WGL's response to OPC DR 1-9.

Q. Did any of your corrections depend on information that was not available to WGL at the time that it used the JANA model to evaluate potential projects?

A. No. All information I used was available to WGL at the time. Where I have used information from 2025 or the test year, WGL would have had the equivalent data from the relevant timeframe.

E. Much of the "risk" WGL seeks to reduce is really the expected cost of routine leak response and repair, not the risk of catastrophic harm.

Q. Returning to your calculation of the split in WGL's risk estimate between safety risk and maintenance burden: —What does the split you derived indicate about how WGL's risk estimates shaped its replacement prioritization?

A. I identified that, by WGL's calculations, just 3 percent of the risk on the system is safety risk, and the other 97 percent is maintenance burden for WGL's expected annual number of leaks. The lopsided nature of this split means that prioritization is going to drive project selection based primarily on a reduction of the maintenance burden, and only secondarily to reduction in explosion or ignition risk. This prioritization is contrary to the philosophy of DIMP and to WGL's obligation to understand and prioritize reduction in the risk to human life, safety, and property. If WGL had corrected its risk analysis, similar to how I have attempted to do so in this testimony, it would have found that close to half of its risk is related to safety, although total risk is lower and few projects may be cost-effective to pursue to reduce risk.

Q. What are the drivers of the risk from routine Grade 1, 2, or 3 leaks?

A. This risk reflects no costs associated with injuries, deaths, or property damage. It includes the cost of leak response, repair or replacement, commodity loss, regulatory and environmental costs, and impact on WGL's reputation. Setting aside WGL's contention that that somehow operating a system with a reasonably predictable number of leaks is somehow harming AltaGas investors by over $100 million dollars per year due to reputational harm, this portion of

WGL's calculated risk simply reflects WGL's estimates of the costs of normal utility operations when operating a system with older assets that tend to develop leaks.

Q. Setting aside your contention that WGL's estimated values for these risks are overestimated, are you concerned with WGL's decision to focus risk reduction on routine leaks?

A. Yes. Addressing the thousands of routine leaks that occur on WGL's system every year is important, and WGL should take action to address those leaks as it becomes aware of them. However, those leak events do not represent the same type of risk as explosions or ignition events that cause injury, death, and property damage. This is evident in the fact that PHMSA requires very different types of reporting for leaks than it does for safety incidents such as explosions or ignition events.

Q. Does replacing leak-prone pipe materials reduce response and repair costs, and can that savings justify prioritizing those replacements?

A. Yes. In some cases, a pipe segment may have so high a likelihood of a leak, and its cost to repair may be so high, that the expected present value of future maintenance on that pipe segment exceeds the cost to replace it with a plastic pipe. Identifying pipe segments like this requires good data about the annual likelihood of leaks on each pipe segment (incorporating asset-specific information and history as much as possible), the cost to respond to and repair a leak, and the cost of replacement. In theory, WGL's JANA implementation could be used to rank pipe segments by expected maintenance burden, if it used accurate likelihood and cost estimates.

Q. What are the potential impacts of focusing risk reduction on addressing routine leaks, rather than explosion or ignition events?

A. WGL's approach systematically de-prioritizes health and safety. By folding routine maintenance burden into its "risk" score alongside health and safety risk, WGL distorts project rankings in a way that systematically disadvantages

true safety investments. Projects offering bulk pipe replacement of leakier materials will rank higher under WGL's metric even if they deliver inferior health and safety benefit per dollar spent. The practical consequence is that WGL's methodology de-prioritizes the very projects best suited to reducing the risk of explosions and ignitions—the events capable of causing the greatest harm to Maryland residents.

F. These costs were imprudently incurred, and the Commission should disallow them.

Q. What are your conclusions regarding the projects selected using the JANA software without a benefit-cost analysis?

A. WGL had sufficient information at hand to know that these projects were not providing benefits to residents or ratepayers that were sufficient to justify their costs. WGL imprudently proceeded to invest in these projects anyway.

Q. What should the Commission do about this imprudence?

A. The Commission should disallow the inclusion of STRIDE projects justified based on JANA modeling, such as those projects listed in Attachment ASH-10. The total resulting gas plant in service reduction from the projects listed in Exhibit KMM-02(b) would be $18,329,672. Additional projects included in the small-project inventory summarized in Exhibit KMM-04 should also be disallowed unless WGL can show they were cost-effective. The Commission should also direct WGL to refund the portion of the STRIDE surcharge already collected corresponding to these projects.

IX. WGL ACTED IMPRUDENTLY BY FAILING TO REVISIT PROJECT DECISIONS WHEN ACTUAL EXECUTION COSTS INCREASED MATERIALLY.

A. Prudence is ongoing and requires utilities to reevaluate projects as better information emerges.

Q. When is WGL responsible for acting prudently?

A. At all times. WGL is responsible for ensuring the prudency of its investments from the initial planning phase through project execution. This responsibility includes reevaluating prudency as situations arise during construction that cause a change in scope or budget.

Q. Do WGL's current practices demonstrate consideration of prudency at every project stage?

A. No. WGL's current processes do not incorporate an adequate review for prudency once project construction is underway.

Q. How many STRIDE projects from January 1, 2023, to September 30, 2025, overran their planned budgets, and by how much?

A. Ninety-six out of the 128 STRIDE projects installed between January 1, 2023, and September 30, 2025, exceeded their planned costs, totaling $16.8 million in overruns, or $12.3 million after reducing for projects that underspent.[89] Fifty projects exceeded 20 percent of their planned costs, and 15 projects exceeded 50 percent of planned costs.

Q. How many STRIDE projects from January 1, 2023, to September 30, 2025, were cancelled or deferred due to cost or scope changes?

A. None.[90]

[89] KMM-02(b).
[90] *See* WGL's response to OPC DR 1-20.

Q. What is WGL's approach for addressing scope or cost changes in projects under construction?

A. On-site construction crews notify WGL management when scope or cost changes become apparent in a project; WGL management then reviews the conditions and approves or rejects any modifications prior to proceeding.[91]

Q. Does WGL recalculate risk-reduction per dollar for projects that have, or are expected to, exceed their original scope and cost?

A. No. WGL does not recalculate risk-reduction per dollar spent for projects with overruns.[92]

B. When a project materially exceeds its estimate, WGL should reconsider whether continued execution remains justified.

Q. What happened with project 303337 (BCA ID#)?

A. WGL exceeded its original cost estimate for this project by 175 percent. During construction for project 303337, WGL identified an additional 80 feet of main in need of replacement due to "the condition of the pipe."[93] Replacing the pipe required night-time construction (required by the State Highway Administrator) and cutting through 30 inches of thick concrete subsurface. WGL incurred additional costs for light towers and traffic-control personnel to enable night-time construction, and additional concrete, asphalt breakage, and vacuum-excavating equipment to address the thick roadway. WGL originally budgeted $516,500 for this project, but spent $1,422,460, translating to a 175 percent cost variance.[94]

[91] *See* WGL's response to OPC DR 1-20.
[92] *See* WGL's response to OPC DR 1-20.
[93] KMM-05, Attachment G, page 1.
[94] KMM-05, Attachment G, page 1.

Q. Did WGL consider alternatives to replacement of the additional 80 feet of main in project 303337?

A. WGL has not demonstrated that it considered alternatives to replacing the additional 80 feet of main.

Q. At what point would it have been prudent for WGL to reconsider the scope of project 303337?

A. WGL should have reevaluated the project as soon as it discovered that the replacement of the additional 80 feet of main required cutting through 30 inches of concrete roadway and night-time construction. At this point, WGL should have reevaluated the cost of the project and assessed alternative solutions.

Q. What alternatives should WGL have considered for this project?

A. WGL should have considered repairing or relining the 80 feet of main. As described in Section X, relining is a trenchless technology that could have avoided the costly activities related to excavating the 30 inches of roadway and night-time construction. Had WGL reevaluated the risk reduction per dollar spent for replacement compared with alternatives, it may have discovered a more cost-effective option to address the main. However, WGL did not conduct this analysis, and proceeded to spend $905,960 over the original estimate.

C. Proceeding with over-budget projects without revisiting cost-effectiveness is further evidence of imprudence.

Q. What are your concerns with WGL's current processes?

A. WGL does not have adequate processes in place to reevaluate scope or cost changes in projects that are under construction, leading to $16.8 million in overruns over the last two and a half years.[95] Proceeding with over-budget

[95] KMM-02(b).

projects without revisiting the cost-effectiveness of alternatives does not demonstrate a sufficient review of prudence.

X. WGL IMPRUDENTLY FAILED TO SUFFICIENTLY EVALUATE LOWER-COST ALTERNATIVES TO FULL REPLACEMENT.

A. WGL's alternative analysis was too limited to satisfy its responsibility to be prudent.

Q. How does witness Murphy describe WGL's consideration of alternatives in its capital planning process?

A. Witness Murphy describes WGL's capital system planning process in broad terms. He states that the process is grounded in engineering best practices and standards and considers, among other things, expected useful life, design options, cost, and "assessment of available alternatives."[96] He also states that, throughout the process, the company "continuously analyzes cost-effective options to defer, reduce, or eliminate the need to replace, upgrade, or construct new system components, including an analysis of non-pipeline alternatives, as appropriate."[97] He also testifies that each project in this case reflects those considerations and was chosen because it offered system improvements benefiting customers. In other words, witness Murphy presents WGL's review of alternatives as an established feature of the company's planning process and as part of the basis for his claim that the resulting investments are reasonable and prudent.

Q. Does Witness Murphy provide project-specific evidence showing that WGL actually compared replacement against concrete lower-cost alternatives for the projects at issue here?

A. No. Witness Murphy provides a high-level description of the company's planning process, but he does not provide project-specific evidence showing what alternatives were considered for STRIDE projects, how those alternatives

[96] Murphy Direct at page 20, line 7.
[97] Murphy Direct at page 20, lines 12–14.

were evaluated, or why replacement was selected over them. His testimony states the conclusion that alternatives were considered, but it does not provide the underlying analysis needed to test that claim on a project-by-project basis. That distinction is important. A general statement that the company considers alternatives is not the same as demonstrating that it actually compared replacement against specific lower-cost options for a given main or service segment. For prudence review, the more important question is what WGL actually did when selecting the challenged projects, not simply how it describes its overall planning philosophy.

Q. Did WGL maintain sufficient records to back up its claims of prudence regarding consideration of alternatives?

A. No. As documented in WGL's response to OPC DR 8-2, which asked for contemporaneous records of WGL's decision-making process, WGL did not maintain contemporaneous records sufficient to show what alternatives it considered for particular projects, how those alternatives were evaluated, or why they were rejected. That means the record lacks the basic decision documents one would expect if alternatives analysis had played a meaningful role in project selection. In my view, that is a significant deficiency. If the company contends that alternatives were part of the prudence basis for these investments, it should be able to produce records showing the alternatives considered and the reasoning that led to replacement. Without those records, the Commission is left with general assurances rather than evidence of the actual decision-making process. I am troubled that WGL would not maintain relevant project-selection records for projects that were not yet included in rate base, and for which it knew that a prudence review had not been conducted.

Q. Why is the absence of contemporaneous documentation relevant to a prudence review?

A. It is relevant because prudence review examines whether the utility acted reasonably based on the information available at the time decisions were made.

Contemporaneous records are the best evidence of what the company knew, what options it considered, and what reasoning it actually used in selecting a project. Without such records, it is much harder to distinguish an actual prudent decision process from an after-the-fact justification. That is especially true here, where WGL seeks to recover large capital costs from customers and where witness Murphy relies on the alleged consideration of alternatives as part of the prudence showing. If alternatives were genuinely considered in a meaningful way, one would expect some contemporaneous documentation of that work. The absence of such documentation weakens the company's claim that the projects it executed were prudent.

Q. Do you believe that WGL's consideration of alternatives was sufficient to demonstrate prudence? Why or why not?

A. Based on WGL's evidence in this case, I do not believe that WGL's consideration of alternatives was sufficient to demonstrate prudence. Witness Murphy describes a process that, in principle, includes consideration of alternatives, but the record does not show that this process produced a concrete, project-specific comparison of replacement against lower-cost options. In addition, WGL's lack of contemporaneous records makes it difficult to verify whether alternatives analysis had any substantive effect on project selection. In my view, a prudent utility should be able to show not only that it has a general planning framework, but also that it actually used that framework to compare alternatives and make reasonable choices on behalf of customers. On this record, that showing has not been made.

Q. When WGL says it "continuously analyzes cost-effective options,"[98] does the company show that such analysis had any meaningful chance of resulting in a decision other than replacement?

A. No. Witness Murphy states that WGL continuously analyzes cost-effective options to defer, reduce, or eliminate the need to replace, upgrade, or construct

[98] Murphy Direct at page 20, line 12.

new components. But he does not identify project examples in which such analysis led WGL to select a materially different, lower-cost alternative instead of replacement for the projects at issue here. As a result, the statement reads more like a description of the company's general planning approach than evidence that alternatives analysis meaningfully constrained replacement spending. In my view, for that statement to support a prudence showing, the company would need to demonstrate that alternatives analysis was capable of changing outcomes in cases with more favorable alternatives, not merely that it was mentioned as part of the process.

B. WGL did not sufficiently pursue non-pipeline alternatives that could have avoided replacement costs.

Q. What is a non-pipeline alternative (NPA)?

A. Maryland's Public Utilities Article (PUA) section 4-214(a) defines NPAs as "an investment or activity that defers, reduces, or eliminates the need to construct a new gas pipeline." NPAs could include demand-side measures such as electrification, energy efficiency, and other measures that reduce or eliminate customers' demand for natural gas for the purpose of avoiding gas infrastructure investments.

Q. What does Maryland law require regarding NPAs?

A. As one of the requirements for receiving approval to recover reasonable and prudent costs, PUA § 4-214(c) requires investor-owned gas companies to demonstrate that they have "analyzed cost-effective options available to defer, reduce, or eliminate the need to replace, upgrade, or construct new components," including an analysis of (i) non-pipeline alternatives for investments unrelated to safety, and (ii) leak detection and repair. Additionally, PUA § 4-210 requires STRIDE plans to include "an analysis that compares the costs of proposed replacement projects with alternatives to replacement, including leak detection and repair."

Q. This Maryland law was not in effect for the full period covered by this rate case. How does that impact your NPA review?

A. The Commission's final order in WGL's previous rate case, 9704, required consideration of NPAs, so it is necessary and appropriate to review WGL's approach to NPAs throughout the period covered by this rate case.[99] In addition to compliance with Commission orders, WGL has an ongoing obligation to behave in a prudent manner to protect the interests of its customers, regardless of a specific NPA law or Commission order. By failing to evaluate alternatives, the company runs a high risk of spending more money than is necessary to achieve the safe and reliable gas system that it is obligated to maintain and operate. If WGL were competing to offer cost-effective service with other firms, and those firms offered lower-cost service because they considered NPAs, WGL's competitive position, and therefore financial results, would suffer.

Q. How does WGL consider NPAs?

A. WGL does not meaningfully consider NPAs. WGL only considers NPAs at a programmatic level during the early stages of capital planning; it does not evaluate NPA opportunities for individual projects.[100] Moreover, WGL states that NPAs are only appropriate when they "do not negatively impact safety, energy reliability, when the NPAs are cost effective, when there is evidence that the NPAs will lower GHG emissions, and when the NPAs do not impede the company's obligation to serve."[101]

[99] *See* Order on Rehearing (Order No. 91079, at 24-25), which states in part "Order No. 90943 requires gas utilities—in this case, WGL—to consider all cost-effective non-pipeline alternative options available to defer, reduce, or remove the need to construct or upgrade components of their natural gas systems, and not solely pursue infrastructure replacement, in order to justify their system safety and reliability spending in the future."
[100] *See* WGL's response to OPC DR 2-8.
[101] *See* WGL's response to OPC DR 2-7.

Q. What types of NPAs does WGL consider?

A. WGL considers energy efficiency and demand response at a programmatic level. It also considers interruptible rates, local supply or storage, and abandonment of unused assets as forms of NPAs.[102] WGL does not consider electrification as an NPA.

Q. What are your concerns with WGL's approach to NPAs?

A. WGL's approach has three fundamental deficiencies. First, by limiting NPA evaluation to early-stage capital planning, WGL forecloses opportunities to deploy NPAs at the project level—which is precisely where PUA § 4-214 requires a demonstrated analysis of whether NPAs can defer, reduce, or eliminate new infrastructure construction. Second, WGL's criteria for determining when an NPA is "appropriate" are so restrictive as to make meaningful NPA consideration unlikely in practice. Third, WGL entirely omits electrification and other demand-side strategies that could reduce system load by incentivizing customers to leave the gas system, thereby avoiding infrastructure investment altogether.

Q. Has WGL provided any evidence that it has made progress implementing NPAs?

A. No. When asked in discovery for the supporting workpapers behind each of the NPAs the company analyzed from January 1, 2023, to September 30, 2025, WGL responded that it was unable to count the number of NPAs it analyzed and did not provide any workpapers or proof of analysis.[103]

Q. Please describe what utilities in other states are doing to implement NPAs.

A. Many utilities across the country are making progress implementing NPAs. Gas utilities in Massachusetts recently developed an NPA framework integrating NPA evaluation into traditional gas planning processes, and are

[102] Murphy Direct at pages 21–25.
[103] *See* WGL's response to OPC DR 2-7.

currently developing targeted-electrification demonstration projects.[104] Consolidated Edison in New York has fully electrified 63 buildings as of November 2025.[105] National Grid has developed an NPA deployment plan for its downstate territory in New York (notably, where National Grid is not the electric provider).[106] Pacific Gas & Electric in California electrified 102 customers and enabled the retirement of 22 miles of pipe as of 2024.[107] Xcel Energy in Colorado received approval to implement a region-wide project that uses NPAs and supplemental supply to avoid constructing new pipeline capacity.[108]

There is plenty of precedent for NPAs from other jurisdictions that WGL can and should learn from to improve its current approach to NPAs.

Q. Has WGL attempted to find opportunities to retire assets through customer electrification?

A. WGL alerts customers whose mains or service lines are planned to be replaced, with a lead time of a year or less.[109] If any of them have electrified and no longer want gas service, WGL will disconnect them. To date, WGL reports

[104] NSTAR Gas Company and Eversource Gas Company of Massachusetts each d/b/a Eversource Energy, Climate Compliance Plan, Exhibit ES-CCP, Attachment 3, NPA Framework, D.P.U. 25-44/25-45, April 1, 2025.
[105] Consolidated Edison Company of New York, Inc., *Non-Pipes Alternatives Annual Expenditures & Program Report*, Case 22-G-0065, November 2025.
[106] The Brooklyn Union Gas Company d/b/a National Grid NY, and Keyspan Gas East Corporation d/b/a National Grid, *Non-Pipe Alternatives Implementation Plan*, Case 23-G-0225 and 23-G-0226, May 7, 2025.
[107] Rocky Mountain Institute and National Grid, "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization" webinar presentation, June 17, 2024.
[108] Public Utilities Commission of the State of Colorado, Commission Decision, *In the Matter of the Application of Public Service Company of Colorado for Approval of the Mountain Energy Project and Associated Certificate of Public Convenience and Necessity for Supplemental Supply*, Proceeding No. 25A-0044EG, November 26, 2025.
[109] Murphy Direct, page 23, states "The Company currently sends notices to all customers affected by planned pipeline replacement projects associated with its STRIDE Plan alerting them to the proposed work on the natural gas system to determine whether the customers are considering replacing their gas appliances with electric alternatives." WGL develops a STRIDE Plan each year, so the notice period must be around a year or less.

that no one has taken up WGL on this.[110] WGL has taken no proactive steps to inform customers further in advance of the replacement project. WGL's actions are comparable to its system review to look for abandoned pipe, rather than actively pursuing lower-cost options through NPAs.

C. WGL did not adequately evaluate relining as an alternative to main replacement.

Q. What is pipe relining?

A. Witness Murphy defines relining as "Lining is a pipe rehabilitation technique that forms a gas-tight barrier within an existing pipe and relies on the existing pipe for structural support."[111] Progressive Pipeline Management (PPM), a major installer of cured-in-place liners for natural gas pipes, provides details about their technology and costs in a "frequently asked questions" document, which states "Cured-In-Place Lining (CIPL) is a trenchless rehabilitation technology designed specifically for natural gas distribution and low pressure transmission pipelines. It rehabilitates leak-prone or corrosion-compromised metallic pipe by installing and curing a bonded composite liner inside the host pipe. The result is a new composite pipeline, elimination of and the structural rehabilitation of the host pipe—extending its useful life by more than 100 years while significantly reducing excavation, avoiding total replacement, and drastic reduction of large-scale restoration. CIPL is effective in diameters from 2 to 48 inches and is applicable to cast iron, bare steel, wrapped steel, and wrought iron mains. It maintains flow capacity, the existing maximum allowable operating pressure (MAOP) and can safely withstand pressures up to 450 psig."[112]

[110] Murphy Direct at page 24.
[111] Murphy Direct at page 24.
[112] Progressive Pipe Management. "About Progressive Pipeline Management (PPM)" Accessed at https://www.progressivepipe.com/cipl-faq on February 26, 2026.

Q. Why is relining a potentially promising alternative to replacement for mains?

A. Rehabilitating leaking or leak-prone pipes with relining technology offers similar benefits to pipe replacements at a potentially lower cost. Pipe replacement requires digging up the pipe and repaving. Liners are a trenchless technology that can be installed while the pipe remains in the ground, thereby avoiding a substantial portion of the costs associated with replacement.

Q. Is relining usable for services?

A. Relining is likely only suitable for relatively large services (2 inches or larger). For small services such as the ones typically serving residential customers, relining might be more hassle than it's worth given the short length and small diameter of a typical service. However, for a large customer whose "service" is similar to a small diameter main (i.e., hundreds of feet long and 2 inches or more in diameter) relining could be a suitable option.

Q. What are the costs of pipe relining?

A. For a 4-inch diameter pipe, PPM estimates a cost of about $276 per foot, or just under $2 million per mile.[113] There are also costs associated with the loss of service to connected customers while the liner is installed. This period has historically been as long as 48 hours, but new technologies are available that can lower that time to 8 to 12 hours. However, customer disconnection can be avoided for pipes with no services directly attached, and where downstream customers have access to a redundant supply.[114]

Q. Has WGL considered relining as an alternative for any projects it proposes to add to rate base in this case?

A. WGL has not presented any evidence that it considered relining for projects it proposes to add to rate base in this case. WGL has not relined any pipe on its

[113] Progressive Pipe Management, *Cured-in-place Lining (CIPL) for the life extension and renewal of natural gas pipelines – Comprehensive FAQ*, attached as Attachment ASH-6.
[114] *See* WGL's response to OPC DR 2-14.

distribution system since 2017,[115] and has not relined any pipe in Maryland in at least 20 years.[116]

Q. Do WGL's project costs and PPM's cost estimates indicate that any of WGL's pipeline replacement projects could have been completed more cost-effectively using a cured-in-place liner?

A. Yes. I calculated the cost per foot of new pipe for STRIDE projects listed in Exhibit KMM-02(b) and compared those costs to the estimated costs provided by PPM in Attachment ASH-6. WGL's cost per foot for projects was generally well more than twice the per-foot cost of relining. This means that even if half the project cost was related to project components (such as services) not addressable with relining, it would still have been less expensive to treat the mains using relining rather than replacement.

Q. Can you walk through an example to illustrate how relining could have avoided costs?

A. Of course. WGL's most expensive STRIDE project from Exhibit KMM-02(b), on a per-foot basis, is BCA0303337, in which WGL "[r]eplaced 861 feet of Bare/unprotected Wrapped Steel main, replaced 35 feet of Contingent Main and installed 825 feet of 6" main Services affected: 6 estimated EFVs: 6" at a cost of $1,422,460. This is a cost of $1,724.19 per foot of newly installed 6-inch pipe. More than 90 percent of this cost is attributable to mains, based on the project's Class 3 estimate. PPM estimates that relining an 8-inch pipe costs $333.50 per foot, or more than five times less (and less than a quarter of the portion of the costs that would be allocated to mains). Even if some costs would still have been incurred to address the six services on this segment of pipe, there could still have been substantial savings. This project is illuminating because it ran well over the estimated cost of $516,500 (which

[115] Murphy Direct at page 24, line 13-25.
[116] *See* WGL's response to OPC DR 2-14.

would still have been $626 per foot). WGL reports that the additional costs were because:

> [c]onstruction required a field change during the main installation process that resulted in the installation of an additional 80 feet of main. The tie-in point at the intersection of Annapolis Road and 64th Avenue was extended in order to abandon an additional section of main due to the condition of the pipe. This change incurred additional costs for labor, materials, traffic control, saw cutting, materials, trucking, and temporary restoration. The main installation was performed at night per request of the State Highway Administration right-of-way inspector resulting in additional spend for light towers, and traffic control personnel and devices. Concrete, asphalt breakage, and vacuum excavating equipment was required during the main and service installation due to 30" thick roadway subsurface (concrete) along Annapolis Road. Also, shoring was required at the tie-in points due to the depth of existing main. An additional 11,850 SF of Mill and Overlay was required to meet Prince George's Specifications and Standards for Road and bridges. This project had an allocation variance due to timing and other considerations.[117]

The project cost more in large part due to costs associated with excavation of the roadway, such as dealing with cutting through an extra-thick roadway and shoring up due to the depth of the main. Additional costs were also required for paving. It would have been prudent for WGL to consider relining based on cost alone, before it encountered conditions in the field. It would have been prudent for WGL to revisit that analysis when it discovered that site conditions required substantial additional resources, particularly when those costs are related to excavation, where relining provides the greatest difference in approach. Instead, WGL imprudently plowed ahead and completed the project at a cost of more than $900,000 over the estimate.

[117] Exhibit KMM-02(b).

Q. Is that the only project for which WGL imprudently chose to ignore relining as an option?

A. No. I count 14 projects totaling over $15 million in expense where WGL paid a total cost of more than $840 per foot of mains replacement. Attachment ASH-7 lists these projects, along with estimates of allocating WGL's cost per foot for mains. (I allocated final costs to mains versus services based on the allocation in WGL's Class 3 cost estimate.) The most cost-effective of these projects had an allocated mains cost of about $468 per foot (BCA0309171), and the average is $644 per foot. These values are far more than PPM's estimated costs for relining. There could be substantial savings from relining even after accounting for some remaining unavoidable costs, as well as addressing services.

Q. Are you certain that WGL should have used relining in these cases?

A. No. I am neither a relining engineer nor do I have enough project-specific information to say that savings would have definitely been possible. However, I am sure that WGL imprudently failed to consider relining as an alternative for these projects and therefore missed any savings that could have been found.

Q. What do you suggest the Commission do about WGL's imprudent process in these cases?

A. I propose that the Commission limit recovery for all mains replacements to no more than the cost per foot of the relevant-sized pipe from PPM's relining-cost estimates, if it finds the replacement otherwise to have been prudently selected.

XI. CONCLUSIONS AND RECOMMENDATIONS

Q. What conclusions do you draw from evidence WGL has presented to date in this case, regarding the prudence of WGL's STRIDE projects?

A. In keeping with Burns et al.'s admonition to "use the standard of reasonableness under the circumstances […] a utility decision must have been reasonable under the circumstances that were known or could have been

known at the time the decision was made,"[118] I was careful to ensure that my review included only information that was available to WGL at the time the decision was made, or would have been available had WGL looked for it. While Burns et al. caution against "supplement[ing] the reasonableness standard for prudence with other standards that look at the final outcome of a utility's decision,"[119] I was willing to give WGL the benefit of the doubt if the projects selected were cost-effective even though WGL had not evaluated them for cost-effectiveness.

I reviewed the aspects of WGL's STRIDE program for which I was able to acquire sufficient evidence to evaluate whether WGL acted prudently even though it had not expressly set out to select projects whose benefits exceeded their costs. Unfortunately, the evidence shows that WGL did not happen to select prudent projects and execute them prudently. My review concludes that WGL acted imprudently. My conclusion is backed up by substantive evidence that creates serious doubt about the prudence of all of WGL's STRIDE investment decisions, including those which I could not evaluate in detail.

Q. Could WGL cure this deficiency?

A. If WGL presents project-level evidence demonstrating that each project's benefits exceeded its costs and that the project was prudently executed, I would reconsider my conclusions and revise my recommendations to the Commission accordingly.

Q. Are your conclusions and recommendations based on a complete analysis of project-level assets?

A. No, they are not. WGL objected to OPC's request for geographic information system (GIS) data for WGL's Maryland system,[120] and the Commission upheld

[118] Attachment ASH-4 at page *iv*.
[119] *Id*.
[120] *See* WGL's response to OPC DR 1-16.

WGL's objection.[121] If I had been able to access this data, I would have been able to conduct a project-level review of the assets contained in, or excluded from, WGL's STRIDE distribution projects proposed for addition to rate base in this proceeding. For example, if the data had been available to me, I would have had the opportunity to examine whether WGL's process of bundling assets into projects and ranking them based on risk reduction per $10,000 was adequate to select the most cost-effective projects, and whether WGL replaced low-risk assets at unnecessary cost.

Q. What conclusions do you draw in this case?

A. I find that:

- The large majority of WGL's estimated risk on its system is the aggregation of high-likelihood, low-consequence risk of leaks that are identified and repaired. Only about 3 percent of WGL's estimated risk corresponds to health, safety, or property damage from explosions or ignition events.

- Excavation and vehicle damage are the leading causes of PHMSA-reportable explosion and ignition events on WGL's system. Of the 19 gas-safety incidents on WGL's three-state system since January 1, 2016, 14 were caused by excavation, vehicle collision, or were otherwise directly human caused. Eleven of these 14 involved damage to plastic pipe (10 installed in 1995 or later), which WGL's risk analysis estimates has a higher likelihood of hazardous leak in excavation incidents than does older steel pipe.

- Replacement of a steel service with plastic provides little if any net benefit in reducing safety incidents. WGL proposes to add to plant in service more than $30 million from replacing vintage mechanically coupled steel service lines based on the justification that those service lines would have some

[121] *See* Commission Order No. 92254 at 3.

number of expected leaks per 100 services, but failed to compare the costs and benefits of replacing service lines to reduce leak frequency. WGL had the information required to make such a comparison. If WGL had conducted a benefit-cost analysis it would have found that it was not cost-effective to replace these service lines based on the value of avoided leaks.

- For STRIDE projects proposed beginning with the 2024 project list, WGL has quantified risk in annual dollars using JANA. WGL could have compared these annual dollar values with the costs to mitigate the risk to determine whether the mitigation action is cost-effective. WGL has not made these comparisons for any of the capital additions that it requests be added to plant in service in this case.

- WGL's JANA risk analysis overstates risk to Marylanders by including the consequence of reputational loss to WGL investors and by using the maximum consequence for each type of potential cost rather than the average cost. WGL failed to quantify risk in a way that can be compared with ratepayer costs.

- If WGL had used the cost information at its disposal (primarily related to the costs to address leaks) to compare project capital costs and expected risk-reduction benefits to Marylanders for its STRIDE projects analyzed using the JANA software and executed since the start of 2024, it would have found that all of the projects it was considering had costs that exceeded the benefits.

- WGL failed to revisit the decision to execute project decisions when costs increased, even when accurate cost information would have resulted in the project not being selected for prioritization.

- WGL failed to evaluate whether alternatives, such as relining and non-pipeline alternatives, could have reduced the cost of its risk-reduction activities.

- By failing to incorporate accurate information about the costs and benefits of pipe replacement and other alternatives into project selection, WGL has over-emphasized reduction in ongoing maintenance burden and under-emphasized reducing the risk of health, safety and property damage. WGL has an obligation to operate a safe and reliable system; its decisions have misallocated resources away from fulfilling that obligation.

Q. What are your recommendations to the PSC based on these conclusions?

A. I recommend that the PSC:

- Find that WGL has not met its burden to show that its STRIDE distribution investments were prudently incurred.

- Find that WGL acted imprudently when it selected services for replacement based on the number of projected leaks per 100 services.

- Exclude investor-oriented benefits from benefit-cost analysis and require WGL to use its average consequence costs for common events.

- Find that WGL acted imprudently when it used a mis-calibrated JANA risk model to select STRIDE projects whose cost exceed their benefits.

- Disallow all $115.1 million of WGL's STRIDE distribution additions to rate base if WGL is unable to provide additional evidence to sufficiently support the prudence and cost-effectiveness of its project selection, and require refund of the STRIDE surcharge collected corresponding to these assets.

- In the event that the Commission declines to accept my recommendation to find that all of WGL's STRIDE distribution investments were imprudently

incurred, it should limit recovery for all mains replacements to no more than the cost per foot of relining using a cured-in-place liner.

- Disallow or limit recovery for projects where WGL failed to evaluate feasible lower-cost alternatives, including non-pipeline alternatives.

Q. Does this conclude your testimony at this time?

A. Yes, it does.

Asa S. Hopkins, **Ph.D.,** Senior Vice President, Consulting

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Senior Vice President*, April 2024 – Present; *Vice President*, April 2019 – April 2024; *Principal Associate*, January 2017 – March 2019.

Conducts research and writes expert testimony and reports related to state energy policy and planning, energy efficiency, strategic electrification, deep decarbonization, and the present and future of electric and gas utility regulatory and business models.

Vermont Public Service Department, Montpelier, VT. *Director of Energy Policy and Planning,* October 2011 – December 2016

State energy planning and utility regulation

• Directed the year-long development of the 2016 Vermont Comprehensive Energy Plan, including stakeholder meetings, public forums, and coordination of contributions from other departments and the Governor's office. Primary author of the executive summary and five chapters.
• Led the Department's approach to establishing budgets and performance targets for energy efficiency utilities. Oversaw staff conducting program evaluation and savings verification.
• Submitted testimony and conducted analysis in support of public advocacy and negotiation in prominent litigated regulatory proceedings.

Policy development, analysis, and advocacy

• Developed the structure of Vermont's 2015 Renewable Energy Standard, including its novel "energy transformation" requirement. Worked with stakeholders to develop support for the policy and with the legislature to shepherd it to passage. This policy will result in more reduction of Vermont's GHG emissions than any others passed in the last 15 years.
• Led execution of Vermont's Total Energy Study, which examined technology and policy pathways for Vermont to meet GHG emission and renewable energy goals.
• Led cost-benefit analysis of Vermont's existing net metering structure and led the development of departmental proposals for a new structure.
• Prepared and delivered public, stakeholder, and interagency presentations, including to agency and business leaders, legislative committees, and the governor.
• Oversaw programs providing financing, technical, and process assistance to clean energy projects.

During tenure, Vermont rose in the rankings on national clean energy state scorecards: ACEEE State Energy Efficiency Scorecard from 5th to 3rd and U.S. Clean Tech Leadership Index from 10th to 3rd.

U.S. Department of Energy, Washington, DC. *Special Advisor to the Under Secretary for Science / AAAS Science and Technology Policy Fellow,* September 2010 – August 2011

Dr. Hopkins served as the assistant project director for the Department of Energy's first Quadrennial Technology Review. In this role, he coordinated a team that solicited input from Department of Energy and National Laboratory staff and scientists, ran a series of public workshops, facilitated coordination with the White House, developed a set of technology assessments, and ultimately drafted the Report on the First QTR, published Sept. 27, 2011.

Lawrence Berkeley National Laboratory, Berkeley, CA. *Environmental Energy Policy Postdoctoral Fellow*, January 2009 – August 2010

Conducted technical and economic analysis to support the Department of Energy in setting the energy efficiency standards that appliances must meet in order to be sold in the United States.

California Institute of Technology, Pasadena, CA. *Graduate Research Fellow,* 2002 – 2008

Los Alamos National Laboratory, Los Alamos, NM. *Post-Baccalaureate Researcher, Theoretical Division,* June 2001 – June 2002

EDUCATION

California Institute of Technology, Pasadena, CA
Doctor of Philosophy in Physics, 2008
Master of Science in Physics, 2007

Haverford College, Haverford, PA
Bachelor of Science *summa cum laude*, in Physics with minors in Computer Science and Growth and Structure of Cities, 2001

SELECTED PROJECTS

The Future of Gas Utilities – Dr. Hopkins leads much of Synapse's work in the area of the future of gas utilities. He and his team are assisting a number of clients to understand the future of gas utilities in the context of deep building decarbonization objectives. This work includes assisting Conservation Law Foundation in Massachusetts Department of Public Utilities Docket 20-80 (an investigation into "the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals"); the Industrial Gas Users Association in evaluation of energy-transition-related business risk to Quebecois and Ontario gas utilities; Natural Resources Defense Council in New York and Nevada's regulatory proceedings regarding the future of gas; the Colorado Energy Office regarding approaches to decision-making in the face of uncertainty, in the context of Colorado's regulatory proceedings regarding gas utility Clean Heat plans and building decarbonization; the County of San Diego (with the University of California San Diego) in developing the buildings and utilities portion of its Regional Decarbonization

Framework; the Maryland Office of People's Counsel in modeling the impact of the state's decarbonization objectives on utility sales and finances; and the District of Columbia Department of Energy and Environment in assessing Washington Gas Light's Climate Business Plan and rate case filings.

Puerto Rico Energy Bureau – Synapse has provided extensive support to Puerto Rico's electricity regulator since 2015. Dr. Hopkins coordinated the engagement from 2018 through 2024, and retains a leadership role. Dr. Hopkins has led or substantially contributed to the development of Puerto Rico's first energy efficiency and demand response regulations; emergency microgrid regulations; and the review of the island's second Integrated Resource Plan and subsequent processes to optimize resilience using both transmission and distributed generation resources.

Massachusetts Comprehensive Energy Plan – On behalf of the Massachusetts Department of Energy Resources (the state energy office), Synapse and Sustainable Energy Advantage assisted DOER and its sister agencies in the development of Massachusetts's first Comprehensive Energy Plan. Dr. Hopkins assisted DOER leadership in defining the scope and approach for the CEP, to distinguish it from other state planning processes. He worked with Pat Knight to develop an approach to modeling energy transformations toward low-carbon alternatives in electricity, buildings, and transportation that are consistent with state policy and approaches while being grounded in stock turnover rates and feasible policies and programs.

Northeastern Regional Assessment of Strategic Electrification – On behalf of the Northeast Energy Efficiency Partnerships, Synapse and Meister Consultants Group identified the opportunity, costs, and benefits available if strategic electrification is adopted as a key strategy for decarbonization in New York and New England. Dr. Hopkins, Kenji Takahashi, and Pat Knight are primary authors of the resulting report, published in July 2017, which characterizes the current markets for efficiency electrification technologies (such as heat pumps and electric vehicles), identifies policies to overcome market barriers, assesses the state of electrification technologies, and models the extent of electrification both possible given market dynamics and required to meet regional greenhouse gas emission goals.

2016 Vermont Comprehensive Energy Plan – Directed the year-long development of the 2016 plan, including setting its strategic approach to current Vermont energy planning challenges and grounding it in quantitative analysis. Developed the public engagement process, then hosted expert stakeholder meetings and public forums. Adapted the results of the 2014 Total Energy Study to produce scenarios that illustrate the proposed pathways identified in the plan. Coordinated contributions from staff and leaders in other departments, and from the Governor's office. Wrote the executive summary and 5 of the 14 chapters.

Total Energy Study – Scoped and led a legislatively-mandated report on policy and technology pathways to meet Vermont's renewable energy and greenhouse gas emission goals. Designed and facilitated a focus-group-based stakeholder engagement process to identify technology and policy visions for analysis. Retained outside modeling consultant, then worked closely with them to build credible business-as-usual and policy case models of Vermont's energy economy to the year 2050 using the

TIMES/FACETS integrated assessment model. Translated those model results to make REMI PI+ calculations of impact on Vermont GDP and jobs. Synthesized qualitative and quantitative results into intermediate and final reports identifying key outcomes for policy design.

Demand Resources Plan Proceedings – In each of three, three-year cycles, led the development of the Department of Public Service's positions regarding appropriate budgets, rate and bill impacts, and performance targets for Vermont's energy efficiency utilities. Analyzed current efficiency utility performance to calibrate expected future performance. Negotiated performance metrics that reflect policy priorities. Developed new regulatory and budget treatment of research and development for behavioral energy efficiency programs.

Quadrennial Technology Review – As Assistant Project Director, managed the project activities of the eight-person core team for the U.S. Department of Energy's first Quadrennial Technology Review. This review of DOE's energy technology activities established a robust framework and codified principles used to build DOE's energy technology portfolio (including identifying the appropriate and highest-leverage activities for DOE relative to the private sector and other government actors). Extensive collaboration and discussions within DOE, as well the public through a series of workshops with industry, government, national laboratory, and academic participation, culminated in the publication of the first DOE-QTR report in September 2011. Coordinated successful stakeholder workshops; facilitated focus groups. Drafted discussion papers that served as the basis for extensive intra- and inter-agency and White House coordination and negotiation. Primary author of the final report's section on building and industrial energy efficiency. Project was completed on schedule and on budget, and met its critical milestones.

REPORTS

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Takahashi, K., A. Hopkins, P. Eash-Gates, E. Carlson, K. Schultz, E. Ashley. 2025. *Strategic Roadmap for Building Decarbonization - Policy, Regulatory, Workforce, and Equity Strategies for a Cleaner, Greener New Jersey.* Synapse Energy Economics and New Jersey agencies for the Governor's Office of Climate Action and the Green Economy.

Takahashi, K., C. Lane, M. Whited, S. Schadler, T. Gyalmo, A. Zeng, A. S. Hopkins. 2024. *Charging Minnesota's Electric Vehicles; Strategies that Work for the Electric Grid and Consumers.* Synapse Energy Economics for Minnesota Department of Commerce, Division of Energy Resources.

Takahashi, K., A. S. Hopkins, E. Carlson, S. Schadler, S. Chavin. 2024. *Memo: Assessment of Electric Grid Headroom for Accommodating Building Electrification (Revised July 2024)*. Synapse Energy Economics to New Yorkers for Clean Power.

Hopkins, A. S., A. Napoleon, S. Schadler, T. Gyalmo. 2024. *The High Cost of New Jersey Gas Utilities' Leak Prone Pipe Replacement Programs 2024.* Synapse Energy Economics for Natural Resources Defense Council.

DeLeon, S., K. Takahashi, E. Carlson, A. S. Hopkins, S. Kwok, J. Litynski, C. Mattioda, L. Metz. 2024. *Minnesota Building Decarbonization Analysis: Equitable and cost-effective pathways toward net-zero emissions for homes and businesses.* Synapse Energy Economics for Clean Heat Minnesota.

Sustainable Energy Advantage and Synapse Energy Economics. 2023. Memo: Data for Use in Economic Analysis of a Clean Heat Standard. For Massachusetts Department of Environmental Protection.

Sustainable Energy Advantage and Synapse Energy Economics. 2023. Memo: Survey of Credit-Based Policies. For Massachusetts Department of Environmental Protection.

Sustainable Energy Advantage and Synapse Energy Economics. 2023. Memo: Options for Role of Electric Distribution Companies (EDCs), Obligated Fuels, and Obligated Entities. For Massachusetts Department of Environmental Protection.

Synapse Energy Economics, Nelson Nygaard, Integral Group, and Siemens PTI. 2023. The Strategic Electrification Roadmap for Buildings and Transportation in the District of Columbia: Resilient, Innovative, and Affordable Electrification. For the District of Columbia Department of Energy and Environment.

Hopkins, A. S., A. Napoleon, K. Schultz. 2023. *The High Cost of New York Gas Utilities' Leak- Prone Pipe Replacement Programs.* Synapse Energy Economics for Natural Resources Defense Council.

Carlson, E., P. Eash-Gates, B. Fagan, A. Hopkins. 2023. *Review of Northwest Natural Gas 2022 Integrated Resource Plan—Final Report: Assessing Compliance with the Oregon IRP Guidelines and the Greenhouse Gas Reduction Requirements from the Climate Protection Program.* Synapse Energy Economics for Staff of Oregon Public Utilities Commission.

Douglas, A., J. Kallay, S. Singh Walker, A. Hopkins, A. Napoleon, & K. Takahashi. 2022. Future Proofing the Texas Grid with Distributed Energy Resources. Synapse Energy Economics for Texas Advanced Energy Business Alliance.

Hopkins, A. S., A. Napoleon, J. Litynski, K. Takahashi, J. Frost, S. Kwok. 2022. *Climate Policy for Maryland's Gas Utilities: Financial Implications*. Synapse Energy Economics for Maryland Office of the People's Counsel.

Kwok, S., K. Takahashi, J. Litynski, A. S. Hopkins. 2022. Memo: Massachusetts DPU Docket-2080: Proposed "Common Regulatory Framework." Synapse Energy Economics for Conservation Law Foundation.

Hopkins, A. S. S. Kwok, J. Litynski, A. Napoleon, K. Takahashi. 2022. Memo: Evaluation of Draft Consultant Reports in Massachusetts DPU Docket 20-80. Synapse Energy Economics for Conservation Law Foundation.

Hopkins, A. S., A. Napoleon, S. Kwok. 2022. *Factsheet: Hydrogen & Low-Carbon Gases in New York's Electricity Future*. Synapse Energy Economics for Sierra Club.

Hopkins A. S., P. Eash-Gates, J. Frost, S. Kwok, J. Litynski, K. Takahashi. 2022. "Decarbonization of Buildings." In *San Diego Regional Decarbonization Framework*, edited by SDG Policy Initiative, School of Global Policy and Strategy, University of California San Diego. San Diego.

Frost, J. S. Kwok, K. Takahashi, A.S. Hopkins, A. Napoleon. 2021. *New York Heat Pump Trajectory Analy*sis. Synapse Energy Economics for NRDC.

Hopkins, A. S., A. Napoleon, K. Takahashi. 2021. *A Framework for Long-Term Gas Utility Planning in Colorado.* Synapse Energy Economics for the Colorado Energy Office.

Woolf, T., A. Napoleon, A. Hopkins, K. Takahashi. 2021. *Long-Term Planning to Support the Transition of New York's Gas Utility Industry*. Synapse Energy Economics for Natural Resources Defense Council.

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Hopkins, A.S., P. Knight, J. Frost. 2021. *Rhode Island Carbon Pricing Study.* Synapse Energy Economics and the Cadmus Group for the Rhode Island Office of Energy Resources.

Kallay, J., A.S. Hopkins, C. Odom, J. Ramey, J. Stevenson. R. Broderick, R. Jeffers, B. Garcia. 2021. *The Quest for Public Purpose Microgrids for Resilience: Considerations for Regulatory Approval.* Synapse Energy Economics for Sandia National Labs.

Takahashi, K., E. Sinclair, A. Napoleon, A. S. Hopkins, D. Goldberg. 2021. *Evaluation of EnergyWise Low-Income Energy Efficiency Program in Mississippi – Program Performance, Design, and Implications for Low-Income Efficiency Programs*. Synapse Energy Economics for Sierra Club and Gulf Coast Community Foundation.

Kallay, J., A. Napoleon, J. Hall, B. Havumaki, A. S. Hopkins, M. Whited, T. Woolf, J. Stevenson, R. Broderick, R. Jeffers, B. Garcia. 2021. *Regulatory Mechanisms to Enable Investments in Electric Utility Resilience.* Synapse Energy Economics for Sandia National Laboratories.

Kallay, J., A. Napoleon, B. Havumaki, J. Hall, C. Odom, A. S. Hopkins, M. Whited, T. Woolf, M. Chang, R. Broderick, R. Jeffers, B. Garcia. 2021. *Performance Metrics to Evaluate Utility Resilience Investments.* Synapse Energy Economics for Sandia National Laboratories.

Kallay, J., S. Letendre, T. Woolf, B. Havumaki, S. Kwok, A. S. Hopkins, R. Broderick, R. Jeffers, K. Jones, M. DeMenno. 2021*. Application of a Standard Approach to Benefit-Cost Analysis for Electric Grid Resilience Investments*. Synapse Energy Economics for Sandia National Laboratories.

Hopkins, A. S., S. Kwok, A. Napoleon, C. Roberto, K. Takahashi. 2021. *Scoping a Future of Gas Study.* Synapse Energy Economics for Conservation Law Foundation.

Kallay, J., A. S. Hopkins, A. Napoleon, B. Havumaki, J. Hall, M. Whited, M. Chang., R. Broderick, R. Jeffers, K. Jones, M. DeMenno. 2021. *The Resilience Planning Landscape for Communities and Electric Utilities.* Synapse Energy Economics for Sandia National Laboratories.

Shipley, J., A. S Hopkins, K. Takahashi, D. Farnsworth, 2021. *Renovating Regulation to Electrify Buildings: A Guide for the Handy Regulator*. Regulatory Assistance Project.

Hopkins, A. S., A. Napoleon, T. Woolf, K. Takahashi. 2021. *Long-Term Planning to Support the Transition of New York's Gas Utility Industry*. Synapse Energy Economics for Natural Resources Defense Council.

Letendre, S., E. Camp, J. Hall, B. Havumaki, A. S. Hopkins, C. Odom, S. Hackel, M. Koolbeck, M. Lord, L. Shaver, X. Zhou. 2020. *Energy Storage in Iowa: Market Analysis and Potential Economic Impact.* Prepared by Synapse Energy Economics and Slipstream for Iowa Economic Development Authority.

Eash-Gates, P., K. Takahashi, D. Goldberg, A. S. Hopkins, S. Kwok. 2021. *Boston Building Emissions Performance Standard: Technical Methods Overview.* Synapse Energy Economics for the City of Boston.

Camp, E., C. Odom, A. S. Hopkins. 2020. *Cost-Effectiveness of Proposed New Mexico Environment Department Oil and Gas Emissions Reduction Rules: Impacts and Co-Benefits of Reduced Volatile Organic Compound Emissions from the Oil and Gas Industry.* Synapse Energy Economics for Environmental Defense Fund.

Camacho, J., K. Takahashi, A. S. Hopkins, D. White. 2020. *Assessment of Proposed Energize Eastside Project*. Synapse Energy Economics and MaxETA Energy for the City of Newcastle, WA.

Takahashi, K., J. Frost, D. Goldberg, A. S. Hopkins, K. Nishio, K. Nakano. 2020. *Survey of U.S. State and Local Building Decarbonization Policies and Programs*. Presented at the 2020 ACEEE Summer Study of Energy Efficiency in Buildings.

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Takahashi, K., A. S. Hopkins, J. Rosenkrantz, D. White, S. Kwok, N. Garner. 2020. *Assessment of National Grid's Long-Term Capacity Report*. Synapse Energy Economics for the Eastern Environmental Law Center.

Camp, E., N. Garner, A. S. Hopkins. 2019. *Cost-Effectiveness of Comprehensive Oil and Gas Emissions Reduction Rules in New Mexico: Impacts of Reduced Methane and Volatile Organic Compound Emissions from the Oil and Gas Industry.* Synapse Energy Economics for the Environmental Defense Fund.

Camp, E., A. S. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Kallay, J., A. S. Hopkins, J. Frost, A. Napoleon, K. Takahashi, J. Slason, G. Freeman, D. Grover, B. Swanson. 2019. *Net Zero Energy Roadmap for the City of Burlington, Vermont*. Synapse Energy Economics and Resource Systems Group for Burlington Electric Department.

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Hopkins, A. S., P. Knight, N. Peluso. 2018. *Massachusetts Comprehensive Energy Plan: Commonwealth and Regional Demand Analysis.* Synapse Energy Economics, Sustainable Energy Advantage, and MA DOER for the Massachusetts Department of Energy Resources.

Knight, P., D. Goldberg, E. Malone, A. S. Hopkins, D. Hurley. 2018. *Getting SMART: Making sense of the Solar Massachusetts Renewable Target (SMART) program*. Synapse Energy Economics for Cape Light Compact.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Woolf, T., A. S. Hopkins, M. Whited, K. Takahashi, A. Napoleon. 2018. *Review of New Brunswick Power's 2018/2019 Rate Case Application.* In the Matter of the New Brunswick Power Corporation and Section 103(1) of the Electricity Act Matter No. 375. Prepared by Synapse Energy Economics for the New Brunswick Energy and Utilities Board Staff.

Hopkins, A. S., K. Takahashi. 2017. *Alternatives to Building a New Mt. Vernon Substation in Washington, DC*. Synapse Energy Economics for the District of Columbia Department of Energy and Environment.

Hopkins, A. S., S. Fields, T. Vitolo. 2017. *Policies to Cost-Effectively Retain Existing Renewables in New York*. Synapse Energy Economics for the Alliance for Clean Energy New York.

Vitolo, T., A. S. Hopkins. 2017. *The Mounting Losses at CWLP's Dallman Station: A Study of the Relative Costs of Operating Each of the Four Dallman Units*. Synapse Energy Economics for the Sierra Club.

Hopkins, A. S., A. Horowitz, P. Knight, K. Takahashi, T. Comings, P. Kreycik, N. Veilleux, J. Koo. 2017. *Northeast Regional Assessment of Strategic Electrification*. Synapse Energy Economics and Meister Consultants Group for the Northeast Energy Efficiency Partnerships.

Vermont Public Service Department. 2016. *Vermont Comprehensive Energy Plan*.

Vermont Public Service Department. 2016. *Act 199 Study on Manufacturing Competitiveness and Energy*.

Vermont Public Service Department. 2014. *Total Energy Study: Final Report on a Total Energy Approach to Meeting the State's Greenhouse Gas and Renewable Energy Goals*.

Vermont Public Service Department. 2014. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 99 of 2014*.

Vermont Public Service Department. 2013. *Total Energy Study: Report to the Vermont General Assembly on Progress Toward a Total Energy Approach to Meeting the State's Greenhouse Gas and Renewable Energy Goals.*

Vermont Public Service Department. 2013. *Evaluation of Net Metering in Vermont Conducted Pursuant to Act 125 of 2012*.

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ARTICLES

Hopkins, A. S., K. Takahashi, S. Nadel. 2020. "Keep warm and carry on: Electrification and efficiency meet the 'polar vortex'." Proceedings of the 2020 ACEEE Summer Study of Energy Efficiency in Buildings.

Hopkins, A. S., K. Takahashi, L. David. 2018. "Challenges and Opportunities for Deep Decarbonization through Strategic Electrification under the Utility Regulatory Structures of the Northeast". Proceedings of the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 2018.

Hopkins, A. S. Review of *Burn Out*, by Dieter Helm, *Science* 356, Issue 6339 (May 2017): 709, https://doi.org/10.1126/science.aam8696

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Hopkins, A. S., K. Jacobs, S. Habib, K. Schwab. 2003. "Feedback Cooling of a Nanomechanical Resonator," *Physical Review B* 68, 235328.

TESTIMONY

Connecticut Public Utilities Regulatory Authority (Docket No. 24-12-01): Joint direct and surrebuttal testimony (with Dr. Sol deLeon) regarding the application of Yankee Gas Services Company D/B/A/ Eversource Energy to amend its rate schedules, with focus on gas capital planning in the context of decarbonization. On behalf of the Connecticut Office of Consumer Counsel, March and April, 2025.

Washington DC Public Service Commission (FC 1180): Provided direct testimony regarding Washington Gas's application for a rate increase. On behalf of the District of Columbia Government, January 2025.

Washington DC Public Service Commission (FC 1179): Provided direct and rejoinder testimony regarding Washington Gas's application for accelerated cost recovery of pipeline replacement costs. On behalf of the District of Columbia Government, December 2024 and October 2025.

Michigan Public Service Commission (Case No. U-21291): Provided direct testimony regarding the application of DTE Gas Company for authority to increase its rates, amend its rate schedules, and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority. On behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club, May, 2024.

Connecticut Public Utilities Regulatory Authority (Docket No. 23-11-02): Direct and surrebuttal testimony regarding the application of Connecticut Natural Gas Corporation and the Southern Connecticut Gas Company to amend their rate schedules, with focus on gas capital planning in the context of decarbonization. On behalf of the Connecticut Office of Consumer Counsel, February and March 2024.

Public Utilities Commission of the State of Colorado (Proceeding No. 23A-0392EG): Answer and cross-answer regarding the application of Public Service Company of Colorado for approval of its 2024-2028 Clean Heat Plan, with focus on rate and bill impacts. On behalf of Sierra Club and Natural Resources Defense Council, January and February 2024.

Maryland Public Service Commission (Case No. 9692): Direct and Surrebuttal Testimony of Asa Hopkins regarding the application of Baltimore Gas and Electric Company for an Electric and Gas Multi-Year Plan. On behalf of the Maryland Office of People's Counsel, August 2023.

Ontario Energy Board (EB-2022-0200): Testified as an expert on the business risk facing Enbridge Gas, Inc. related to the energy transition and other risks, as part of a rate case proceeding to set the utility's capital structure. On behalf of the Industrial Gas Users Association, 2023.

Washington DC Public Service Commission (FC 1169): Provided direct and rebuttal expert testimony regarding Washington Gas's application for an increase in rates, from the standpoint of the District of

Columbia's climate and clean energy policies. On behalf of the District of Columbia Government, November 2022 and January 2023.

New York Public Utilities Commission (Case No. 22-E-0064 and 22-G-0065): Direct and Rebuttal Testimony of Alice Napoleon and Asa Hopkins regarding Con Edison's proposed gas-side investments as greenhouse gas mitigation strategies and gas extension allowance rule changes and the need for long-term planning for the gas system and adequacy of the company's non-pipe alternatives framework. On behalf of Natural Resources Defense Council, May 2022.

Régie de l'énergie du Québec (R-4156-2021): Testified as an expert on the business risk facing Quebec's natural gas utilities related to the energy transition, as part of a proceeding to set the utilities' cost of capital and capital structure. On behalf of the Industrial Gas Users Association, 2022.

Vermont Public Utility Commission (Case No. 21-1107-PET and 21-1109-PET): Addressed the impact of GlobalFoundries proposed "self-managed utility" on the general good of the state and Vermont's energy policy, with particular focus on the impact on environmental soundness and greenhouse gas emissions mitigation. On behalf of Conservation Law Foundation, June 2021.

Public Service Commission of Wisconsin (Docket No. 5-CG-106): Addressed the need for a pair of liquified natural gas facilities in light of the fossil fuel use reductions required to meet state and federal goals for mitigating climate change and the potential for cost-effective demand-side alternatives. On behalf of the Sierra Club, June 2021.

Vermont Senate Finance Committee: Provided expert testimony in the form of a presentation entitled "Updating Vermont's Renewable Energy Standard" to the Vermont Senate Finance Committee in January of 2020. Dr. Hopkins presented on the history of the standard, what has changed since 2015, and future potential.

Vermont Public Utility Commission (Case No. 17-1247-NMP): Addressed the consistency of a proposed solar generation facility with the Vermont Comprehensive Energy Plan. On behalf of Derby GLC Solar LLC, January 2018.

Washington DC Public Service Commission (FC 1142): Provided expert testimony regarding the merits of the proposed merger of Washington Gas and AltaGas, Ltd. with respect to the impact on environmental quality, with particular emphasis on the impact of utility management and its approach to climate change on the ability of the District to achieve its climate change mitigation goals. On behalf of the District of Columbia Government.

Régie de l'énergie du Québec (R-3986-2016): Provided an expert report and testimony regarding best practices in utility demand response programs, in the context of Hydro Québec Distribution's ten-year Supply Plan. On behalf of the Regroupment national des conseils régionaux de l'environment du Québec (RNCREQ).

Vermont Public Service Board (Dockets No. 8586 and 8685): Addressed the need for a proposed solar PV generator and its associated contract under PURPA rates, its economic impact on the state, and its

consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, July 2016.

Vermont Public Service Board (Docket No. 8684): Proposed avoided energy and capacity cost rates for use in Rule 4.100, Vermont's implementation of PURPA. On behalf of the Vermont Department of Public Service, October 2015 and May 2016.

Vermont Public Service Board (Docket No. 8600): Addressed the need for a proposed solar PV generator, its economic impact on the state, and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, March 2016.

Vermont Public Service Board (Docket No. 8525): Introduced a memorandum of understanding between the DPS and Green Mountain Power regarding a proposed rate design, with particular focus on new critical peak price rates to be available and marketed. On behalf of the Vermont Department of Public Service, November 2015.

Vermont Public Service Board (Docket No. 7970): Addressed whether increases in the expected cost of a gas pipeline expansion project were sufficient to warrant reopening the underlying proceeding, particularly with respect to the need for the project, the economic impact on the state, and consistency with the general good of the state and the Vermont Comprehensive Energy Plan. On behalf of the Vermont Department of Public Service, May 2015.

Vermont Public Service Board (Docket No. 8311): Addressed how statutory criteria for the use of electric energy efficiency funds for electrification measures (such as heat pumps) might be met. On behalf of the Vermont Department of Public Service, January 2015.

Vermont Public Service Board (Docket No. 7862): Presented the Department's positions regarding whether Entergy Vermont Yankee should be granted a continued certificate of public good, with particular focus on the need for the plant, the economic benefit of continued operation, consistency with the Vermont Electric Plan, and whether continued operation by Entergy was in the general good of the state. On behalf of the Vermont Department of Public Service, October 2012 and April 2013.

Vermont Public Service Board (Docket No. 7833): Addressed the need for a proposed biomass electric generator and its consistency with the Vermont Electric Plan. On behalf of the Vermont Department of Public Service, October and November 2012; February and September 2013.

Vermont Public Service Board (Docket No. 7770): Addressed a number of topics related to the merger of Green Mountain Power and Central Vermont Public Service, most particularly the disposition of a windfall repayment due to ratepayers. On behalf of the Vermont Department of Public Service, January and March 2012.

Vermont Public Service Board (Docket No. 7815): Addressed consistency of a proposed long-term PPA with the Vermont Electric Plan and the utility's integrated resource plan. On behalf of the Vermont Department of Public Service, January 2012.

SELECTED PRESENTATIONS

Hopkins, A. S. "Coming Challenges to the Gas Distribution Utility Status Quo" presented at the Future of Heat Initiative, November 2024.

Hopkins, A. S. "Rising Gas Rates: The Need for Consumer-Focused Leadership in Light of a Looming Death Spiral" presented at the National Association of State Utility Consumer Advocates, November 2024.

Hopkins, A. S. "Analysis and Activism: The Gas Distribution Utility Status Quo is Unsustainable" presented at the Caltech Y Social Activism Speaker Series, November 2024.

Hopkins, A. S., R. Haefer, J. Slason, J. Tamerius. "Task 2: Long-Distance Travel Charging Needs" presenting to Massachusetts EV Infrastructure Coordinating Council, June 2024.

Hopkins, A. S., R. Haefer, J. Tamerius. "Update on EVI Demand Modeling" presenting to Massachusetts EV Infrastructure Coordinating Council, June 2023.

Hopkins, A. S., S. Kwok, A. Napoleon, K. Schultz, K. Takahashi. "Massachusetts Clean Heat Standard: Policy and Regulatory Analysis" presented with Conservation Law Foundation, February 2023.

Hopkins, A. S. "IIJA, IRA, and the Growing Federal Role in Transmission—and Why States Should Care," presented at the National Association of State Energy Officials Annual Meeting, October 2022.

Hopkins, A. S., J. Litynski, A. Takasugi. "Policy approaches to increasing electricity affordability in California," presented to various California stakeholders on behalf of Natural Resources Defense Council, February 2022.

Shipley, J., Hopkins, A. S., Takahashi, K., & Farnsworth, D. "Renovating regulation to electrify buildings: A guide for the handy regulator," presented with Regulatory Assistance Project, January 2021.

Hopkins, A. S. 2019. "Efficiency, Electrification, and Renewables in New England and Puerto Rico" at 2019 ACEEE Energy Efficiency as a Resource Conference, October 2019.

Hopkins, A. S. 2019. "Strategic electrification and winter cold snaps: A resource and a challenge" at 2019 ACEEE Energy Efficiency as a Resource Conference, October 2019.

Panelist on "Deep Dive Session on State and Local Electrification Roadmaps" at Electric Power Research Institute (EPRI)/Northeast Energy Efficiency Partnerships (NEEP) Electrification Summit, August 2019.

Hopkins. A. S., K. Takahashi, D. Lis. 2018. "Decarbonization through Strategic Electrification Meets Utilities and Regulation in the Northeast" at the 2018 ACEEE Summer Study on Energy Efficiency in Buildings, August 2018.

Hopkins, A. S. 2019. "Strategic Electrification: Impacts and approaches to meeting decarbonization goals in the northeastern states (and elsewhere)" at Lawrence Berkeley National Laboratory, Energy Technologies Area, August 2018.

Hopkins, A. S. 2017. "Utility Performance Regulation" at the Western States Regional Meeting of the National Association of State Energy Officials, April 2017.

Panelist on "A Regulatory Perspective of Grid Transformation" at the IEEE Innovative Smart Grid Technologies Conference, September 2016.

Panelist on the "Comprehensive Energy Plan Update" at the Renewable Energy Vermont Conference, October 2015.

Hopkins, A. S. 2015. "Vermont's Total Energy Study." Presentation at the National Association of State Energy Officials Energy Policy Outlook Conference, February 2015.

Panelist on "The Role of Energy Efficiency in Mitigating Winter Peak Issues" at the Association of Energy Services Professionals (Northeast Chapter) & Northeast Energy Efficiency Council, November 2014.

Hopkins, A. S. 2014. "Total Energy Study." Presentation at the Renewable Energy Vermont Conference, October 2014.

Panelist on "State Energy & Economic Policy Impacts on Industry Transformation" at the Power Industry Transformation Summit, April 2014.

Hopkins, A. S. 2008. "Mobilizing Pasadena Democrats: Measuring the Effects of Partisan Campaign Contacts." Presentation at the American Political Science Association Annual Meeting, August 2008.

HONORS, AWARDS, AND FELLOWSHIPS

Certified Public Manager, 2014

AAAS Science and Technology Policy Fellowship, 2010 – 2011

Dean's Award for Community Service, 2009

Delegate to the 2004 Democratic National Convention

NSF Graduate Research Fellow, 2002 – 2005

Los Alamos National Laboratory Student Distinguished Performance Award, 2002

Two-time first-team Academic All American, 2000 and 2001

Barry M. Goldwater Scholar, 1999 – 2001

OTHER ACTIVITIES

NASEO - Electricity Committee: Affiliate Co-Chair, 2020-present

Newton, MA Citizens Commission on Energy: Member 2017-2024, Co-Chair 2023-2024

Guest on Synapse Energy Economics, Inc.'s *Energy Nerd Show,* Aug 6, 2020

Board Member, National Association of State Energy Officials, 2015-16

Industrial Advisory Board for ARPA-E-funded project “Packetized Energy Management,” 2016

Burlington, VT Public Works Commission: Member 2012 –2014, Chair 2015

Resume updated July 2025

Washington Gas Light Company's Application for Authority to Increase Rates and Charges for Natural Gas Services

Case No. 9849

Data Responses Referenced in the Direct Testimony of Dr. Asa S. Hopkins

Washington Gas Light Response to OPC Data Request 1-1

Washington Gas Light Response to OPC Data Request 1-2 - CONFIDENTIAL
Attachments omitted from public version

Washington Gas Light Response to OPC Data Request 1-3

Washington Gas Light Response to OPC Data Request 1-4

Washington Gas Light Response to OPC Data Request 1-6 - CONFIDENTIAL
Attachments omitted from public version

Washington Gas Light Response to OPC Data Request 1-7

Washington Gas Light Response to OPC Data Request 1-8 - CONFIDENTIAL
Attachments omitted from public version

Washington Gas Light Response to OPC Data Request 1-9 - CONFIDENTIAL
Attachments omitted from public version

Washington Gas Light Response to OPC Data Request 1-12

Washington Gas Light Response to OPC Data Request 1-13

Washington Gas Light Response to OPC Data Request 1-20

Washington Gas Light Response to OPC Data Request 2-1

Washington Gas Light Response to OPC Data Request 2-2

Washington Gas Light Response to OPC Data Request 2-7

Washington Gas Light Response to OPC Data Request 2-8

Washington Gas Light Response to OPC Data Request 2-14

Washington Gas Light Response to OPC Data Request 2-19

Washington Gas Light Response to OPC Data Request 6-1

Washington Gas Light Response to OPC Data Request 6-3

Washington Gas Light Response to OPC Data Request 8-2

Washington Gas Light Response to OPC Data Request 10-3

Washington Gas Light Response to OPC Data Request 10-5

Washington Gas Light Response to OPC Data Request 11-1

Washington Gas Light Response to OPC Data Request 11-2

Washington Gas Light Response to OPC Data Request 11-3

Washington Gas Light Response to OPC Data Request 11-5

Washington Gas Light Response to OPC Data Request 12-1

Washington Gas Light Response to OPC Data Request 13-1

Washington Gas Light Response to OPC Data Request 15-1

Washington Gas Light Response to OPC Data Request 15-4

Washington Gas Light Response to STAFF Data Request 8-9

Washington Gas Light Response to STAFF Data Request 8-21

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-1

Q. Please refer to Murphy Direct at page 30, lines 3-11.

a. Provide all analysis (including workpapers, process documentation, inputs, assumptions, and results, in working and unlocked electronic format) the Company has conducted that quantifies the benefits that WGL customers receive from "accelerating the replacement of targeted materials and facilities within the Company's system that have been identified as higher risk," on either a per-project basis or across all capital investments proposed for inclusion in rate base in this proceeding.

b. Provide all analysis (including workpapers, process documentation, inputs, assumptions, and results, in working and unlocked electronic format) the Company has conducted that quantifies the costs that WGL customers will bear from "accelerating the replacement of targeted materials and facilities within the Company's system that have been identified as higher risk," on either a per-project basis or across all capital investments proposed for inclusion in rate base in this proceeding.

c. Has the Company conducted a cost-benefit analysis of "accelerating the replacement of targeted materials and facilities within the Company's system that have been identified as higher risk," on either a per-project basis or across all capital investments proposed for inclusion in rate base in this proceeding.

    i. If so, please provide that cost-benefit analysis, including all workpapers, process documentation, inputs, assumptions, and results, in working and unlocked electronic format.

WASHINGTON GAS' RESPONSE **February 26, 2026**

A. The Company provides project lists, semi-annual and annual reports of the STRIDE projects which include the project origination (including the risk reduced per $10,000 spent), project estimates and project actuals for the miles of main retired, the number of services remediated, the number of meters remediated, the number of gaugelines completed, the number of EFVs installed, and the total project expenditures. The Company also calculates the GHG reductions associated with its STRIDE projects in its Independent Auditor Report, Schedule F.

The Company is providing the following attachments with this response:

- "CN 9849 OPC DR 1-1 Attachment 01" – 2023 Updated Project List
- "CN 9849 OPC DR 1-1 Attachment 02" – 2023 Annual Report
- "CN 9849 OPC DR 1-1 Attachment 03" – 2024 Updated Project List
- "CN 9849 OPC DR 1-1 Attachment 04" – 2024 Annual Report
- "CN 9849 OPC DR 1-1 Attachment 05" – 2025 Updated Project List
- "CN 9849 OPC DR 1-1 Attachment 06" – 2025 Semi-Annual Report
- "CN 9849 OPC DR 1-1 Attachment 07" – Schedule F of the Independent Auditor Report Year 2023 STRIDE Plan
- "CN 9849 OPC DR 1-1 Attachment 08" – Schedule F of the Independent Auditor Report Year 2024 STRIDE Plan

a. See the response to subpart (a).

b. No. The reference testimony refers to the Company's STRIDE Projects. These projects provide risk mitigation benefits to customers, as detailed in Exhibit KMM-02. As Witness Murphy explains (p. 14-15), the Company's DIMP Plan in conjunction with its risk ranking tool (specifically, the JANA Lighthouse ("JANA") model beginning in 2023 a probabilistic risk model, and before that, Optimain) were relied upon to prioritize assets for replacement. In 2020, PHMSA identified the use of a probabilistic risk model, which JANA is, as a best practice to evaluate the likelihood of an individual pipe segment failing, the scenarios that may occur due to a failure, and the potential consequences associated with those scenarios (health and safety implications, property damage, repair costs, and others). The Company prioritizes assets as candidates for replacement by using a 'risk reduced per dollar spent' metric during its risk mitigation planning. Ranking alternatives in this fashion maximizes the effectiveness of the dollars spent on projects to deliver the most benefit to customers.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-3

Q. Please refer to Exhibit KMM-02(b), column "Customer Benefits/ Risk Mitigated".

a. Please explain each term in the first cell in this column: "2530 61 Mitigatable Risk per $10k (Rank #40)"

b. What does "2530 61" mean? Is there an implied decimal point between the two numbers?

i. In other locations in this column, do two numbers separated by a space mean an implied decimal point between them?

c. What software or tool did the Company use to quantify the mitigable risk for this project?

d. Provide the complete list of items ranked by "Mitigatable Risk per $10k" on which the first project is ranked #40.

WASHINGTON GAS' RESPONSE **February 26, 2026**

A.

a. The number "2530.61" represents the numerical value of "mitigatable risk per $10k." "Mitigatable risk per $10k" represents the amount of the JANA DIMP model's calculated risk that would be mitigated by the replacement of the vintage assets in a given bundle or BCA divided by the cost of the project in $10k increments. The ranking of the JANA bundle (Rank #40) was based on the numerical value of mitigated risk per $10k arranged in descending order for all the JANA bundles within the Project List year after scope evaluation and engineering design.

The JANA bundles within the Project Year List are ranked in descending order by "mitigatable risk per 10k" after elimination of the following: (i) bundles that were included in the prior year's list; (ii) service-only bundles that were combined and for

which the "mitigatable risk per $10k" was recalculated; and (iii) bundles that were not STRIDE eligible.

b. There should be a decimal point where the two numbers are separated by a space for the numbers listed in that column. The decimal points can be seen on the Excel version of KMM-02(b) which is available on the SharePoint site.

c. The Company utilized the JANA DIMP risk model for this project.

d. BCA No. 309171 was proposed on the CY 2025 STRIDE Project List. Please see Case No. 9708, ML #313301 at Exhibit 1, page 14 of 15, filed on Nov. 1, 2024, available here: https://webpscxb.pscmaryland.com/D171MS/case/9708

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Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
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OPC DATA REQUEST NO. 1

QUESTION NO. 1-4

Q. Please refer to Exhibit KMM-02(b).

a. On what date did WGL begin to use the JANA Lighthouse software as an input for project selection?

b. Did WGL use the JANA Lighthouse software for all risk quantification and mitigation values presented in this exhibit?

c. If WGL used other software or risk analysis than JANA Lighthouse:

i. Please identify each other piece of software or analysis used for risk quantification for project contained in this exhibit, and explain why the Company used that software or analysis.

ii. Please identify with specificity which risk quantification software tool, analysis, or program the Company used to quantify the risk for each line in this exhibit.

WASHINGTON GAS' RESPONSE **February 26, 2026**

A.

a. As explained in the direct testimony of Company witness Murphy on page 14, implementation of JANA for distribution mains and services was complete as of 2023 and was used to identify mains and services projects that were included in the Company's 2024 STRIDE project list. In 2025, the Company's project list included both main and service as well as service-only projects that were informed by the JANA risk model. JANA is currently being used for the evaluation of risk and replacement planning of all distribution mains and services. The blueprinting for the implementation of JANA for the other asset classes such as transmission, facilities, and storage was completed in 2024. Projects to move to a JANA risk model for these other asset classes

will be incrementally implemented. A project to implement the JANA transmission risk model was recently completed.

b. The Company relied on JANA beginning in 2023, and before that, Optimain DS to prioritize its STRIDE distribution projects, as well as Combined Risk Ranking of LP Zones, the Leak/quad analysis discussed in the Company's response to OPC DR 1-5, Field Assessment by Field Operations, Subject Matter Expert ("SME") risk analysis input and TIMP Risk model for transmission projects.

c. See the responses to subparts (a) and (b) and attachment "CN 9849 OPC DR 1 – 4 Attachment 01."

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

STRIDE Capital Projects Placed into Service Between January 1, 2023 and September 30, 2025 (Larger Projects)

Project ID	BCA	GPIS Additions $ (Sorted Largest to Smallest)	Project Name	Project Type	STRIDE Program	Project Location	Project Description/ Scope	Customer Benefits/ Risk Mitigated	STRIDE Filing Estimated Cost ($) *(Includes Cost of Removal)*
BCA0309171	309171	$ 3,207,347	MD STRIDE 3 - MAIN & SVC - OLIVER ST/QUAD T011NE - JANA 102313 - PG	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Replaced 3043 feet of Vintage Mechanically Coupled Steel main and installed 3077 feet of 2" main Services affected: 118 estimated EFVs: 113	2530.61 Mitigatable Risk per $10k (Rank #40)	$ 3,656,476
BCA0307732	307732	$ 1,619,139	MD - STRIDE 6 - MC LP ZONE 7 - FLOWER AVE PH4- MO	Distribution	PROGRAM 6: Zone-Based Low-Pressure Program	Montgomery County	Replaced 1247 feet of Cast Iron main, replaced 183 feet of Bare/unprotected Wrapped Steel main, replaced 1193 feet of Contingent Main and installed 1925 feet of 2" main Services affected: 44 estimated EFVs: 44	LP Zone 7 (Remediation Rank #1 from Table 1.0 : Combined Risk Ranking of LP Zones)	$ 1,831,454
BCA0303411	303411	$ 1,543,081	MD - STRIDE 3 - MEEM AVE - 72246 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 2415 feet of Vintage Mechanically Coupled Steel main and installed 2640 feet of 2" main Services affected: 42 estimated EFVs: 42	Risk/Leak Based (#83 Rank)	$ 1,304,500
BCA0307730	307730	$ 1,521,726	MD - STRIDE 6 - MC LP ZONE 7 - FLOWER AVE PH3 - MO	Distribution	PROGRAM 6: Zone-Based Low-Pressure Program	Montgomery County	Replaced 1940 feet of Cast Iron main, replaced 48 feet of Contingent Main and installed 2030 feet of 2" main Services affected: 37 estimated EFVs: 37	LP Zone 7 (Remediation Rank #1 from Table 1.0 : Combined Risk Ranking of LP Zones)	$ 1,388,605
BCA0301520	301520	$ 1,512,681	MD STRIDE 3 - BLUHILL RD ~ 70457 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 2753 feet of Bare/unprotected Wrapped Steel main and installed 2770 feet of 2" main Services affected: 69 estimated EFVs: 67	Risk/Leak Based (#24 Rank)	$ 1,676,600
BCA0305244	305244	$ 1,445,914	MD STRIDE 3 - SVC ONLY - PG CO SOUTH - 2023 - SUB ID 3204	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 43 estimated EFVs: 42	33.33 Projected Leaks per 100 Services	$ 1,335,700
BCA0303337	303337	$ 1,317,025	MD - STRIDE 2 - ANNAPOLIS RD - 61315 - PG	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Prince George's County	Replaced 861 feet of Bare/unprotected Wrapped Steel main, replaced 35 feet of Contingent Main and installed 825 feet of 6" main Services affected: 6 estimated EFVs: 6	Risk/Leak Based (#40 Rank)	$ 516,500
BCA0307729	307729	$ 1,294,286	MD - STRIDE 6 - MC LP ZONE 7 - FLOWER AVE PH2 - MO	Distribution	PROGRAM 6: Zone-Based Low-Pressure Program	Montgomery County	Replaced 1714 feet of Cast Iron main, replaced 28 feet of Contingent Main and installed 1750 feet of 2" main Services affected: 33 estimated EFVs: 33	LP Zone 7 (Remediation Rank #1 from Table 1.0 : Combined Risk Ranking of LP Zones)	$ 1,096,824
BCA0307081	307081	$ 1,229,888	MD - STRIDE 3 - THISTLE DR - JANA 15780 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1431 feet of Vintage Mechanically Coupled Steel main, replaced 8 feet of Contingent Main and installed 1477 feet of 2" main Services affected: 33 estimated EFVs: 33	Risk/Leak Based (#13 Rank)	$ 942,000
BCA0305263	305263	$ 1,222,417	MD STRIDE 3 - SVC ONLY - MANOR WOODS 2 - 2023 - SUB ID 887	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 28 estimated EFVs: 25	32.97 Projected Leaks per 100 Services	$ 515,900
BCA0304183	304183	$ 1,215,110	MD STRIDE 1A - SVC ONLY - MONTGOMERY 1A - 2023 - SUB ID 857	Distribution	PROGRAM 1A: All Bare and/or Unprotected Steel Services	Montgomery County	Services affected: 44 estimated EFVs: 43	88.89 Projected Leaks per 100 Services	$ 1,016,700
BCA0296356	296356	$ 1,140,636	MD STRIDE 2 - JULEP AVE~67989 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1771 feet of Bare/unprotected Wrapped Steel main, replaced 277 feet of Contingent Main and installed 865 feet of 2" main, installed 1140 feet of 4" main Services affected: 65 estimated EFVs: 60	Risk/Leak Based (#8 Rank)	$ 1,290,700
BCA0303467	303467	$ 1,123,451	MD - STRIDE 2 - HOMESTEAD DR - 77523 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1830 feet of Bare/unprotected Wrapped Steel main and installed 1775 feet of 2" main Services affected: 34 estimated EFVs: 34	Risk/Leak Based (#89 Rank)	$ 897,300
BCA0307068	307068	$ 1,113,788	MD - STRIDE 3 - DEBORAH CT - JANA 87870 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1754 feet of Vintage Mechanically Coupled Steel main, replaced 4 feet of Contingent Main and installed 1845 feet of 2" main Services affected: 38 estimated EFVs: 38	Risk/Leak Based (#3 Rank)	$ 1,140,928
BCA0303343	303343	$ 1,108,694	MD - STRIDE 2 - OAKFORD PL - 80221 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1677 feet of Bare/unprotected Wrapped Steel main and installed 1110 feet of 2" main, installed 645 feet of 4" main Services affected: 33 estimated EFVs: 33	Risk/Leak Based (#47 Rank)	$ 955,700
BCA0307070	307070	$ 1,097,881	MD - STRIDE 3 - CONOVER DR - JANA 15550 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1715 feet of Vintage Mechanically Coupled Steel main, replaced 22 feet of Contingent Main and installed 1737 feet of 2" main, installed 33 feet of 4" main Services affected: 43 estimated EFVs: 42	Risk/Leak Based (#5 Rank)	$ 1,156,850

Project ID	BCA	GPIS Additions $ (Sorted Largest to Smallest)	Project Name	Project Type	STRIDE Program	Project Location	Project Description/ Scope	Customer Benefits/ Risk Mitigated	STRIDE Filing Estimated Cost ($) *(Includes Cost of Removal)*
BCA0303349	303349	$ 1,078,623	MD - STRIDE 2 - HARVEY RD - 114267 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 2143 feet of Bare/unprotected Wrapped Steel main and installed 862 feet of 2" main, installed 1298 feet of 4" main Services affected: 58 estimated EFVs: 51	Risk/Leak Based (#54 Rank)	$ 1,345,300
BCA0299428	299428	$ 1,061,413	MD STRIDE 3 - CRISFIELD RD ~ 70724 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1915 feet of Vintage Mechanically Coupled Steel main and installed 1935 feet of 2" main Services affected: 44 estimated EFVs: 42	Risk/Leak Based (#93 Rank)	$ 1,034,300
FPT0000082	N/A	$ 1,040,751	Plug Valve Replacement, ILI Readiness - Strip 15 Valve 15	Transmission	Program 5 (Transmission): Replacement of Components of DOT Transmission and High-Pressure Pipes to Enable the Use of In-line Inspection Tools ("ILI")	Montgomery County	Replace existing 24" plug valve (Strip 15, valve 15) with a 24" ball valve and 6" blow off with 12 " x6" reducer.	The new ball valve allows for passage of in-line inspection (ILI) tools (e.g., pigs), which allows for better measurement of the integrity of the pipe.	$ 562,900
BCA0303372	303372	$ 1,006,800	MD - STRIDE 3 - MATEY RD - 70701 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1892 feet of Vintage Mechanically Coupled Steel main and installed 1910 feet of 2" main Services affected: 37 estimated EFVs: 37	Risk/Leak Based (#57 Rank)	$ 968,500
BCA0303389	303389	$ 1,003,528	MD - STRIDE 3 - MARBURY RD - 65407 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 2045 feet of Vintage Mechanically Coupled Steel main and installed 2030 feet of 2" main Services affected: 47 estimated EFVs: 41	Risk/Leak Based (#75 Rank)	$ 1,146,700
BCA0303478	303478	$ 997,542	MD - STRIDE 2 - FRANKLIN ST - 69744 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1529 feet of Bare/unprotected Wrapped Steel main and installed 1540 feet of 2" main Services affected: 27 estimated EFVs: 23	Risk/Leak Based (#110 Rank)	$ 737,500
BCA0304241	304241	$ 970,982	MD STRIDE 3 - SVC ONLY - E ROCKVILLE CIVIC ASSOCIATION 1 - 2023 - SUB ID 21626	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 42 estimated EFVs: 42	33.52 Projected Leaks per 100 Services	$ 747,100
BCA0304223	304223	$ 969,830	MD STRIDE 3 - SVC ONLY - REGENCY ESTATES 2 - 2023 - SUB ID 1464	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 38 estimated EFVs: 36	42.11 Projected Leaks per 100 Services	$ 736,700
BCA0305245	305245	$ 924,071	MD STRIDE 3 - SVC ONLY - PG CO NORTH - 2023 - SUB ID 4917	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 31 estimated EFVs: 30	33.33 Projected Leaks per 100 Services	$ 981,100
BCA0305264	305264	$ 920,369	MD STRIDE 3 - SVC ONLY - PG CO - LEWISDALE - 2023 - SUB ID 6241	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 46 estimated EFVs: 45	32.43 Projected Leaks per 100 Services	$ 879,300
BCA0303288	303288	$ 920,038	MD - STRIDE 2 - HOLDRIDGE RD - 76138 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1430 feet of Bare/unprotected Wrapped Steel main, replaced 12 feet of Contingent Main and installed 775 feet of 2" main, installed 695 feet of 4" main Services affected: 28 estimated EFVs: 28	Risk/Leak Based (#3 Rank)	$ 842,600
BCA0303412	303412	$ 918,792	MD - STRIDE 2 - GRANT AVE - 76675 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1545 feet of Bare/unprotected Wrapped Steel main and installed 1575 feet of 2" main Services affected: 41 estimated EFVs: 41	Risk/Leak Based (#87 Rank)	$ 842,200
BCA0306197	306197	$ 915,035	MD STRIDE 3 - SVC ONLY - COLLEGE PARK AND MUNICIPALITIES - 2024 - SUB ID 4866	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 39 estimated EFVs: 39	68.75 Projected Leaks per 100 Services including storm drain, water main, and sanitary sewer	$ 754,000
BCA0307071	307071	$ 913,369	MD - STRIDE 3 - CORSICA DR - JANA 87753 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1460 feet of Vintage Mechanically Coupled Steel main and installed 1465 feet of 2" main Services affected: 35 estimated EFVs: 32	Risk/Leak Based (#6 Rank)	$ 964,218
BCA0301522	301522	$ 913,087	MD STRIDE 2 - NORMANDY DR ~ 80691 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1742 feet of Bare/unprotected Wrapped Steel main, replaced 6 feet of Contingent Main and installed 1755 feet of 2" main Services affected: 37 estimated EFVs: 37	Risk/Leak Based (#14 Rank)	$ 923,600
BCA0309824	309824	$ 907,509	MD STRIDE 2 - MAIN & SVC - SMALLWOOD DR - FIELD OPS - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1523 feet of Bare/unprotected Wrapped Steel main and installed 843 feet of 2" main, installed 430 feet of 4" main Services affected: 34 estimated EFVs: 32	Field Ops Originated	$ 930,604
BCA0310514	310514	$ 907,375	MD STRIDE 3 - SVC ONLY - MO INSP DIST 5 - 2025 - QUAD G030NW - JANA 104578	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 24 estimated EFVs: 24	4888.36 Mitigatable Risk per $10k (Rank #2)	$ 686,512
BCA0303408	303408	$ 895,886	MD - STRIDE 2 - GARLAND AVE - 68341 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	This project includes LP to MP replacement. Replaced 244 feet of Cast Iron main, replaced 1669 feet of Bare/unprotected Wrapped Steel main and installed 1020 feet of 2" main, installed 450 feet of 4" main Services affected: 25 estimated EFVs: 24	Risk/Leak Based (#82 Rank)	$ 742,300

Project ID	BCA	GPIS Additions $ (Sorted Largest to Smallest)	Project Name	Project Type	STRIDE Program	Project Location	Project Description/ Scope	Customer Benefits/ Risk Mitigated	STRIDE Filing Estimated Cost ($) *(Includes Cost of Removal)*
FPT0000050	N/A	$ 871,391	Strip 15 Walt Whitman RCV	Transmission	Program 2 (Transmission): Remote Control Valve Installation	Bethesda, MD	Install an RCV at Strip 15 Valve 13	To enable rapid isolation of pipeline segments in the event of a rupture within high consequence areas	$ 2,053,867
BCA0303340	303340	$ 870,223	MD - STRIDE 3 - RADIUS RD - 76489 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1669 feet of Vintage Mechanically Coupled Steel main and installed 1685 feet of 2" main Services affected: 46 estimated EFVs: 41	Risk/Leak Based (#41 Rank)	$ 1,075,600
BCA0303377	303377	$ 855,801	MD - STRIDE 3 - MORI DR - 77091 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 430 feet of Bare/unprotected Wrapped Steel main, replaced 1443 feet of Vintage Mechanically Coupled Steel main and installed 1455 feet of 2" main Services affected: 27 estimated EFVs: 27	Risk/Leak Based (#62 Rank)	$ 839,100
BCA0305254	305254	$ 846,777	MD STRIDE 3 - SVC ONLY - INSP DIST 8 - 2023 - SUB ID 21732	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 38 estimated EFVs: 37	33.33 Projected Leaks per 100 Services	$ 710,600
BCA0304174	304174	$ 839,132	MD STRIDE 3 - SVC ONLY - INSP DIST 2 & 8 - TWINBROOK- 2023 - SUB ID 21624	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 30 estimated EFVs: 28	94.39 Projected Leaks per 100 Services	$ 818,700
BCA0303311	303311	$ 809,734	MD - STRIDE 2 - CEDAR LN - 79100 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 782 feet of Bare/unprotected Wrapped Steel main and installed 790 feet of 4" main Services affected: 7 estimated EFVs: 7	Risk/Leak Based (#19 Rank)	$ 436,800
BCA0303346	303346	$ 805,680	MD - STRIDE 2 - LEWIS AVE - 74496 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 753 feet of Bare/unprotected Wrapped Steel main, replaced 83 feet of Contingent Main and installed 640 feet of 4" main, installed 125 feet of 6" main Services affected: 19 estimated EFVs: 19	Risk/Leak Based (#51 Rank)	$ 527,600
BCA0303934	303934	$ 803,704	MD - STRIDE 3 - TILDEN LN - JANA "BCA - 303934" - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1132 feet of Vintage Mechanically Coupled Steel main and installed 1095 feet of 2" main Services affected: 26 estimated EFVs: 26	Risk/Leak Based (#24 Rank)	$ 797,511
BCA0303469	303469	$ 797,300	MD - STRIDE 3 - NORTHCREST DR - 60599 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1330 feet of Vintage Mechanically Coupled Steel main and installed 1340 feet of 2" main Services affected: 20 estimated EFVs: 20	Risk/Leak Based (#92 Rank)	$ 722,800
BCA0304242	304242	$ 777,734	MD STRIDE 3 - SVC ONLY - E ROCKVILLE CIVIC ASSOCIATION 2 - 2023 - SUB ID 21626	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 42 estimated EFVs: 42	33.52 Projected Leaks per 100 Services	$ 829,000
BCA0307069	307069	$ 777,435	MD - STRIDE 3 - LAWNSBERRY TER - JANA 15823 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1087 feet of Vintage Mechanically Coupled Steel main, replaced 124 feet of Contingent Main and installed 1235 feet of 2" main Services affected: 33 estimated EFVs: 32	Risk/Leak Based (#4 Rank)	$ 749,768
BCA0300125	300125	$ 772,791	MD STRIDE 2 - BLUHILL RD ~ 70538 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1167 feet of Bare/unprotected Wrapped Steel main and installed 380 feet of 2" main, installed 745 feet of 4" main Services affected: 27 estimated EFVs: 25	Risk/Leak Based (#28 Rank)	$ 719,600
BCA0307749	307749	$ 764,498	MD - STRIDE 6 - MC LP ZONE 7 - CARROLL AVE PH1 - MO	Distribution	PROGRAM 6: Zone-Based Low-Pressure Program	Montgomery County	Replace existing Cast Iron and Bare/unprotected Wrapped Steel mains with 2" plastic; also replace 45 affected services and EFVs.	LP Zone 7 (Remediation Rank #1 from Table 1.0: Combined Risk Ranking of LP Zones)	$ 1,230,459
BCA0303293	303293	$ 753,739	MD - STRIDE 2 - AURORA DR - 41312 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1473 feet of Bare/unprotected Wrapped Steel main and installed 1480 feet of 2" main Services affected: 43 estimated EFVs: 43	Risk/Leak Based (#15 Rank)	$ 890,700
BCA0304212	304212	$ 751,457	MD STRIDE 3 - SVC ONLY - PG CO SOUTHEAST - BROADVIEW - 2023 - SUB ID 7959	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 24 estimated EFVs: 24	55.56 Projected Leaks per 100 Services	$ 685,900
BCA0303338	303338	$ 741,096	MD - STRIDE 3 - GOODHILL RD - 71165 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1178 feet of Vintage Mechanically Coupled Steel main, replaced 21 feet of Contingent Main and installed 1200 feet of 2" main, installed 30 feet of 4" main Services affected: 24 estimated EFVs: 24	Risk/Leak Based (#38 Rank)	$ 700,600
BCA0300111	300111	$ 738,044	MD STRIDE 3 - MONTPELIER RD ~ 70073 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1373 feet of Vintage Mechanically Coupled Steel main, replaced 187 feet of Contingent Main and installed 1535 feet of 2" main Services affected: 24 estimated EFVs: 23	Risk/Leak Based (#107 Rank)	$ 728,700
BCA0292811	292811	$ 726,809	MD STRIDE 3 - E DIAMOND AVE ~ 73546 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 2122 feet of Vintage Mechanically Coupled Steel main and installed 2912 feet of 2" main Services affected: 34 estimated EFVs: 26	Risk/Leak Based (#4 Rank), CY22 Carryover Project	$ 1,392,884

Project ID	BCA	GPIS Additions $ (Sorted Largest to Smallest)	Project Name	Project Type	STRIDE Program	Project Location	Project Description/ Scope	Customer Benefits/ Risk Mitigated	STRIDE Filing Estimated Cost ($) *(Includes Cost of Removal)*
BCA0303390	303390	$ 717,773	MD - STRIDE 2 - CREST RD - 67857 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	This project includes LP to MP replacement. Replaced 1307 feet of Bare/unprotected Wrapped Steel main, replaced 40 feet of Contingent Main and installed 1405 feet of 2" main Services affected: 34 estimated EFVs: 34	Risk/Leak Based (#81 Rank)	$ 768,100
BCA0301521	301521	$ 713,633	MD STRIDE 2 - CARSON ST ~ 91214 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1420 feet of Bare/unprotected Wrapped Steel main and installed 1420 feet of 2" main Services affected: 42 estimated EFVs: 42	Risk/Leak Based (#23 Rank)	$ 823,800
BCA0305249	305249	$ 712,198	MD STRIDE 3 - SVC ONLY - INSP DIST 3 - 2023 - SUB ID 769	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 21 estimated EFVs: 19	33.33 Projected Leaks per 100 Services	$ 369,088
BCA0300122	300122	$ 707,633	MD STRIDE 2 - EASTWOOD AVE ~ 80652 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1044 feet of Bare/unprotected Wrapped Steel main and installed 1085 feet of 4" main Services affected: 15 estimated EFVs: 15	Risk/Leak Based (#13 Rank)	$ 584,600
BCA0307202	307202	$ 689,698	MD - STRIDE 3 - ASTORIA RD - JANA 15736 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1039 feet of Vintage Mechanically Coupled Steel main and installed 1097 feet of 2" main Services affected: 26 estimated EFVs: 25	Risk/Leak Based (#22 Rank)	$ 766,369
BCA0305265	305265	$ 689,599	MD STRIDE 3 - SVC ONLY - ROCKVILLE 1 - 2023 - SUB ID 21566	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 33 estimated EFVs: 33	32.04 Projected Leaks per 100 Services	$ 691,600
BCA0306204	306204	$ 675,643	MD STRIDE 3 - SVC ONLY - PG NORTHEAST INNER - 2024 - SUB ID 7919	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 27 estimated EFVs: 26	75.86 Projected Leaks per 100 Services	$ 532,836
BCA0303290	303290	$ 667,745	MD - STRIDE 2 - EDGEMONT ST - 70673 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1150 feet of Bare/unprotected Wrapped Steel main, replaced 5 feet of Contingent Main and installed 1165 feet of 2" main Services affected: 23 estimated EFVs: 23	Risk/Leak Based (#7 Rank)	$ 601,100
BCA0304240	304240	$ 661,509	MD STRIDE 3 - SVC ONLY - RANDOLPH HILLS 3 - 2023 - SUB ID 157	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 54 estimated EFVs: 54	34.24 Projected Leaks per 100 Services	$ 758,610
BCA0305266	305266	$ 661,161	MD STRIDE 3 - SVC ONLY - ROCKVILLE 2 - 2023 - SUB ID 21566	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 36 estimated EFVs: 31	32.04 Projected Leaks per 100 Services	$ 712,800
BCA0310515	310515	$ 655,413	MD STRIDE 3 - SVC ONLY - PRINCE GEORGES - 2025 - QUAD I008SE - JANA 103135	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 27 estimated EFVs: 26	4238.27 Mitigatable Risk per $10k (Rank #4)	$ 700,929
BCA0305250	305250	$ 651,698	MD STRIDE 3 - SVC ONLY - PG CO SMALL MUNICIPALITIES PART 2 - 2023 - SUB ID 3055	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 37 estimated EFVs: 36	33.33 Projected Leaks per 100 Services	$ 786,200
BCA0303385	303385	$ 644,844	MD - STRIDE 2 - TIMBERWOOD AVE	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 1065 feet of Bare/unprotected Wrapped Steel main and installed 1040 feet of 2" main Services affected: 25 estimated EFVs: 25	Risk/Leak Based (#70 Rank)	$ 567,000
BCA0309156	309156	$ 627,917	MD STRIDE 1A - SVC ONLY - OAKMONT - 2025 - QUAD Y036NW - JANA 106704	Distribution	PROGRAM 1A: All Bare and/or Unprotected Steel Services	Montgomery County	Services affected: 24 estimated EFVs: 21	2506.88 Mitigatable Risk per $10k (Rank #43)	$ 555,440
BCA0309107	309107	$ 627,752	MD STRIDE 3 - SVC ONLY - WHEATON WOODS - 2025 - QUAD L028NW - JANA 100779	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 62 estimated EFVs: 60	2649.79 Mitigatable Risk per $10k (Rank #34)	$ 1,481,523
BCA0303387	303387	$ 624,612	MD - STRIDE 2 - COLESVILLE RD - 113210 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 822 feet of Bare/unprotected Wrapped Steel main and installed 840 feet of 4" main Services affected: 5 estimated EFVs: 4	Risk/Leak Based (#72 Rank)	$ 462,700
BCA0303348	303348	$ 623,235	MD - STRIDE 2 - SAUL RD - 69976 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 558 feet of Bare/unprotected Wrapped Steel main, replaced 216 feet of Contingent Main and installed 760 feet of 6" main Services affected: 15 estimated EFVs: 15	Risk/Leak Based (#53 Rank)	$ 543,100
BCA0301517	301517	$ 621,476	MD STRIDE 3 - HIDDEN CREEK RD ~ 62703 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1289 feet of Vintage Mechanically Coupled Steel main and installed 1300 feet of 2" main Services affected: 8 estimated EFVs: 8	Risk/Leak Based (#61 Rank)	$ 609,400
BCA0303468	303468	$ 606,345	MD - STRIDE 2 - SEVEN LOCKS RD - 361795 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 570 feet of Bare/unprotected Wrapped Steel main and installed 640 feet of 4" main Services affected: 12 estimated EFVs: 12	Risk/Leak Based (#90 Rank)	$ 354,700

Project ID	BCA	GPIS Additions $ (Sorted Largest to Smallest)	Project Name	Project Type	STRIDE Program	Project Location	Project Description/ Scope	Customer Benefits/ Risk Mitigated	STRIDE Filing Estimated Cost ($) *(Includes Cost of Removal)*
BCA0303379	303379	$ 602,676	MD - STRIDE 2 - WILSON LN - 310068 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 702 feet of Bare/unprotected Wrapped Steel main, replaced 13 feet of Contingent Main and installed 20 feet of 2" main, installed 740 feet of 8" main Services affected: 2 estimated EFVs: 2	Risk/Leak Based (#16 Rank)	$ 625,100
BCA0304203	304203	$ 595,058	MD STRIDE 3 - SVC ONLY - INSP DIST 4 - 2023 - SUB ID 767	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 32 estimated EFVs: 30	71.43 Projected Leaks per 100 Services	$ 388,600
BCA0301278	301278	$ 592,482	MD STRIDE 1A - SVC ONLY - INSP DIST 4 NORTH - 2022 - SUB ID 804	Distribution	PROGRAM 1A: All Bare and/or Unprotected Steel Services	Montgomery County	Services affected: 38 estimated EFVs: 33	66.67 Projected Leaks per 100 Services, CY22 Carryover Project	$ 667,664
BCA0310502	310502	$ 587,551	MD STRIDE 3 - SVC ONLY - MO INSP DIST 8 - 2025 - QUAD S029NW - JANA 102973	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 46 estimated EFVs: 40	3651.52 Mitigatable Risk per $10k (Rank #9)	$ 1,069,689
BCA0309214	309214	$ 583,789	MD STRIDE 1A - SVC ONLY - GLENMONT VILLAGE - 2025 - QUAD G025NW - JANA 104906	Distribution	PROGRAM 1A: All Bare and/or Unprotected Steel Services	Montgomery County	Services affected: 17 estimated EFVs: 17	3620.17 Mitigatable Risk per $10k (Rank #10)	$ 419,019
BCA0304235	304235	$ 580,012	MD STRIDE 3 - SVC ONLY - SHERWOOD FOREST MANOR 2 - 2023 - SUB ID 710	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 33 estimated EFVs: 32	34.38 Projected Leaks per 100 Services	$ 554,500
BCA0304243	304243	$ 570,874	MD STRIDE 3 - SVC ONLY - E ROCKVILLE CIVIC ASSOCIATION 3 - 2023 - SUB ID 21626	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 34 estimated EFVs: 34	33.52 Projected Leaks per 100 Services	$ 633,000
BCA0307065	307065	$ 566,793	MD - STRIDE 3 - CHAPMAN RD - JANA 15693 - PG	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Replaced 584 feet of Vintage Mechanically Coupled Steel main, replaced 245 feet of Contingent Main and installed 875 feet of 2" main Services affected: 17 estimated EFVs: 17	Risk/Leak Based (#1 Rank)	$ 670,222
BCA0300422	300422	$ 562,700	MD STRIDE 2 - MILFORD AVE ~ 66835 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 687 feet of Bare/unprotected Wrapped Steel main, replaced 90 feet of Vintage Mechanically Coupled Steel main, replaced 100 feet of Contingent Main and installed 790 feet of 2" main Services affected: 26 estimated EFVs: 26	Risk/Leak Based (#73 Rank)	$ 497,600
BCA0305262	305262	$ 550,651	MD STRIDE 3 - SVC ONLY - MANOR WOODS 1 - 2023 - SUB ID 887	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 31 estimated EFVs: 31	32.97 Projected Leaks per 100 Services	$ 504,400
BCA0307201	307201	$ 545,595	MD - STRIDE 3 - LANCE CT - JANA 88333 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 841 feet of Vintage Mechanically Coupled Steel main, replaced 7 feet of Contingent Main and installed 866 feet of 2" main Services affected: 19 estimated EFVs: 18	Risk/Leak Based (#21 Rank)	$ 570,230
BCA0304193	304193	$ 528,304	MD STRIDE 1B - SVC ONLY - PRINCE GEORGE'S 1B - 2023 - SUB ID 5186	Distribution	PROGRAM 1B: Targeted Copper Services	Prince George's County	Services affected: 31 estimated EFVs: 26	85.71 Projected Leaks per 100 Services	$ 416,000
BCA0301524	301524	$ 510,584	MD STRIDE 2 - 62ND AVE ~ 61286 - PG	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Prince George's County	Replaced 1052 feet of Bare/unprotected Wrapped Steel main and installed 900 feet of 2" main, installed 150 feet of 4" main Services affected: 30 estimated EFVs: 30	Risk/Leak Based (#21 Rank)	$ 673,982
BCA0309167	309167	$ 506,860	MD STRIDE 3 - SVC ONLY - WHEATON WOODS - 2025 - QUAD K028NW - JANA 106960	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 36 estimated EFVs: 36	2434.16 Mitigatable Risk per $10k (Rank #48)	$ 872,339
BCA0303470	303470	$ 498,790	MD - STRIDE 2 - MENLO AVE - 76425 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 850 feet of Bare/unprotected Wrapped Steel main, replaced 26 feet of Contingent Main and installed 820 feet of 2" main Services affected: 17 estimated EFVs: 15	Risk/Leak Based (#96 Rank)	$ 389,900
BCA0306301	306301	$ 497,975	MD STRIDE 3 - SVC ONLY - MO INSP DIST 3 NE - 2024 - SUB ID 344	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 36 estimated EFVs: 36	87.5 Projected Leaks per 100 Services	$ 715,784
BCA0304217	304217	$ 493,085	MD STRIDE 3 - SVC ONLY - PARKWOOD - 2023 - SUB ID 518	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 25 estimated EFVs: 21	45.83 Projected Leaks per 100 Services	$ 469,700
BCA0299358	299358	$ 492,474	MD STRIDE 3 - PARKWOOD TER ~ 77554 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1052 feet of Vintage Mechanically Coupled Steel main and installed 1060 feet of 2" main Services affected: 24 estimated EFVs: 22	Risk/Leak Based (#65 Rank)	$ 565,200
BCA0305267	305267	$ 488,895	MD STRIDE 3 - SVC ONLY - ROCK CREEK MANOR - 2023 - SUB ID 851	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 26 estimated EFVs: 26	31.71 Projected Leaks per 100 Services	$ 543,100
BCA0304190	304190	$ 480,291	MD STRIDE 3 - SVC ONLY - HYATTSVILLE - 2023 - SUB ID 8778	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 31 estimated EFVs: 31	87.50 Projected Leaks per 100 Services	$ 521,000
BCA0303384	303384	$ 480,081	MD - STRIDE 2 - HARRIET LN - 70751 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 687 feet of Bare/unprotected Wrapped Steel main, replaced 5 feet of Contingent Main and installed 715 feet of 2" main Services affected: 17 estimated EFVs: 17	Risk/Leak Based (#68 Rank)	$ 392,100
BCA0304225	304225	$ 464,670	MD STRIDE 3 - SVC ONLY - KINGSWELL SUB - 2023 - SUB ID 776	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 27 estimated EFVs: 27	38.30 Projected Leaks per 100 Services	$ 522,500
BCA0310513	310513	$ 464,136	MD STRIDE 1A - SVC ONLY - MO INSP DIST 3 - 2025 - QUAD A015NE - JANA 103285	Distribution	PROGRAM 1A: All Bare and/or Unprotected Steel Services	Montgomery County	Services affected: 21 estimated EFVs: 19	4901.25 Mitigatable Risk per $10k (Rank #1)	$ 481,221

Project ID	BCA	GPIS Additions $ (Sorted Largest to Smallest)	Project Name	Project Type	STRIDE Program	Project Location	Project Description/ Scope	Customer Benefits/ Risk Mitigated	STRIDE Filing Estimated Cost ($) *(Includes Cost of Removal)*
BCA0304222	304222	$ 457,464	MD STRIDE 3 - SVC ONLY - REGENCY ESTATES 1 - 2023 - SUB ID 1464	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 27 estimated EFVs: 27	42.11 Projected Leaks per 100 Services	$ 525,500
BCA0303407	303407	$ 455,543	MD - STRIDE 2 - S STONES STREET AVE - 389244 -MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 112 feet of Bare/unprotected Wrapped Steel main, replaced 518 feet of Vintage Mechanically Coupled Steel main, replaced 8 feet of Contingent Main and installed 660 feet of 2" main Services affected: 6 estimated EFVs: 6	Risk/Leak Based (#27 Rank)	$ 307,100
BCA0305255	305255	$ 450,783	MD STRIDE 1C - SVC ONLY - PRINCE GEORGE'S 1C PART 2 - 2023 - SUB ID 4272	Distribution	PROGRAM 1C: Targeted pre-1975 Plastic Services	Prince George's County	Services affected: 17 estimated EFVs: 16	33.33 Projected Leaks per 100 Services	$ 273,600
BCA0307073	307073	$ 450,321	MD - STRIDE 3 - LINDEN CT - JANA 88121 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 571 feet of Vintage Mechanically Coupled Steel main and installed 677 feet of 2" main Services affected: 17 estimated EFVs: 17	priority within DC/MD/VA Non-Program Eligible Main.	$ 480,836
BCA0301282	301282	$ 448,280	MD STRIDE 1A - SVC ONLY - INSP DIST 4 S - SUB ID 942 - 2022	Distribution	PROGRAM 1A: All Bare and/or Unprotected Steel Services	Montgomery County	Services affected: 41 estimated EFVs: 38	50 PROJECTED LEAKS PER 100 SERVICES, CY22 Carryover Project	$ 523,358
BCA0305257	305257	$ 446,611	MD STRIDE 3 - SVC ONLY - STONEYBROOK ESTATES - 2023 - SUB ID 781	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 31 estimated EFVs: 31	33.33 Projected Leaks per 100 Services	$ 473,700
BCA0303339	303339	$ 445,092	MD - STRIDE 2 - LOUGHBOROUGH PL - 70101 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 665 feet of Bare/unprotected Wrapped Steel main and installed 360 feet of 2" main, installed 275 feet of 4" main, installed 210 feet of 6" main Services affected: 6 estimated EFVs: 6	Risk/Leak Based (#42 Rank)	$ 423,800
BCA0306230	306230	$ 439,906	MD STRIDE 3 - SVC ONLY - MO INSP DIST 4 - ROCK CREEK EST - 2024 - SUB ID 1100	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 20 estimated EFVs: 16	87.5 Projected Leaks per 100 Services	$ 406,160
BCA0304231	304231	$ 438,969	MD STRIDE 3 - SVC ONLY - CHARRED OAK ESTATES - 2023 - SUB ID 206	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 26 estimated EFVs: 26	34.78 Projected Leaks per 100 Services	$ 458,100
BCA0304198	304198	$ 434,295	MD STRIDE 1C - SVC ONLY - MONTGOMERY 1C - 2023 - SUB ID 21624	Distribution	PROGRAM 1C: Targeted pre-1975 Plastic Services	Montgomery County	Services affected: 11 estimated EFVs: 11	80.00 Projected Leaks per 100 Services	$ 446,100
BCA0301509	301509	$ 432,808	MD STRIDE 3 - DUNSTER LN ~ 73119 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 2461 feet of Vintage Mechanically Coupled Steel main and installed 2480 feet of 2" main Services affected: 43 estimated EFVs: 43	RISK/LEAK BASED (#71 RANK), CY22 Carryover Project	$ 1,104,697
BCA0304226	304226	$ 431,903	MD STRIDE 3 - SVC ONLY - HOME ACRES - 2023 - SUB ID 8767	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Services affected: 22 estimated EFVs: 20	38.24 Projected Leaks per 100 Services	$ 364,800
BCA0304205	304205	$ 429,473	MD STRIDE 3 - SVC ONLY - INSP DIST 5 - CARROLL KNOLLS - 2023 - SUB ID 391	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 24 estimated EFVs: 24	69.64 Projected Leaks per 100 Services	$ 605,800
BCA0303475	303475	$ 427,788	MD - STRIDE 2 - N VAN BUREN ST - 74937 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 630 feet of Bare/unprotected Wrapped Steel main, replaced 10 feet of Contingent Main and installed 640 feet of 4" main Services affected: 20 estimated EFVs: 19	Risk/Leak Based (#102 Rank)	$ 435,700
BCA0304216	304216	$ 427,044	MD STRIDE 3 - SVC ONLY - WOODMONT PARK - 2023 - SUB ID 21538	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 16 estimated EFVs: 16	50.00 Projected Leaks per 100 Services	$ 442,200
BCA0305248	305248	$ 419,563	MD STRIDE 3 - SVC ONLY - INSP DIST 4,5,7,9 - 2023 - SUB ID 1710	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 19 estimated EFVs: 18	33.33 Projected Leaks per 100 Services	$ 347,500
BCA0303341	303341	$ 414,858	MD - STRIDE 2 - DENLEY RD - 76120 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 582 feet of Bare/unprotected Wrapped Steel main, replaced 38 feet of Contingent Main and installed 650 feet of 4" main Services affected: 4 estimated EFVs: 4	Risk/Leak Based (#43 Rank)	$ 344,800
BCA0304233	304233	$ 413,799	MD STRIDE 3 - SVC ONLY - SHERWOOD FOREST MANOR 1 - 2023 - SUB ID 710	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 30 estimated EFVs: 29	34.38 Projected Leaks per 100 Services	$ 423,900
BCA0304237	304237	$ 409,562	MD STRIDE 3 - SVC ONLY - RANDOLPH HILLS 1 - 2023 - SUB ID 157	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 38 estimated EFVs: 38	34.24 Projected Leaks per 100 Services	$ 543,348
BCA0310498	310498	$ 408,777	MD STRIDE 1A - SVC ONLY - MO INSP DIST 8 - 2025 - QUAD X030NW - JANA 105111	Distribution	PROGRAM 1A: All Bare and/or Unprotected Steel Services	Montgomery County	Services affected: 16 estimated EFVs: 15	4411.26 Mitigatable Risk per $10k (Rank #3)	$ 572,082
BCA0301429	301429	$ 407,013	MD STRIDE 3 - HOLMHURST RD ~ 73988 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 1723 feet of Vintage Mechanically Coupled Steel main, replaced 272 feet of Contingent Main and installed 2010 feet of 2" main Services affected: 52 estimated EFVs: 41	Risk/Leak Based (#41 Rank), CY22 Carryover Project	$ 1,080,469
BCA0303476	303476	$ 404,740	MD - STRIDE 2 - GLENNON DR - 73932 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 373 feet of Bare/unprotected Wrapped Steel main, replaced 110 feet of Vintage Mechanically Coupled Steel main and installed 462 feet of 2" main, installed 20 feet of 4" main Services affected: 7 estimated EFVs: 7	Risk/Leak Based (#103 Rank)	$ 213,700
BCA0304213	304213	$ 404,364	MD STRIDE 3 - SVC ONLY - HILLANDALE - 2023 - SUB ID 189	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County and Prince George's County	Services affected: 23 estimated EFVs: 22	52.94 Projected Leaks per 100 Services	$ 404,800

Project ID	BCA	GPIS Additions $ (Sorted Largest to Smallest)	Project Name	Project Type	STRIDE Program	Project Location	Project Description/ Scope	Customer Benefits/ Risk Mitigated	STRIDE Filing Estimated Cost ($) *(Includes Cost of Removal)*
BCA0303376	303376	$ 404,328	MD - STRIDE 2 - WOODFIELD RD - 78423 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 965 feet of Bare/unprotected Wrapped Steel main and installed 990 feet of 2" main Services affected: 23 estimated EFVs: 23	Risk/Leak Based (#63 Rank)	$ 509,400
BCA0307080	307080	$ 401,831	MD - STRIDE 3 - NEWINGTON RD - JANA 87724 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 821 feet of Vintage Mechanically Coupled Steel main and installed 818 feet of 2" main Services affected: 15 estimated EFVs: 15	Risk/Leak Based (#12 Rank)	$ 491,895
FPT0000081	N/A	$ 393,586	Strip 15 Vlv 13 and Tee Removal	Transmission	Program 5 (Transmission): Replacement of Components of DOT Transmission and High-Pressure Pipes to Enable the Use of In-line Inspection Tools ("ILI")	Bethesda, MD	Replace a non-piggable fitting from Strip 15	To enable Strip 15 to be inspected using in-line inspection (ILI) tools for integrity assessment	$ 837,113
BCA0303317	303317	$ 392,974	MD - STRIDE 2 - MARSHALL AVE - 68130 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 790 feet of Bare/unprotected Wrapped Steel main and installed 335 feet of 2" main, installed 365 feet of 4" main Services affected: 15 estimated EFVs: 15	Risk/Leak Based (#36 Rank)	$ 395,000
BCA0309326	309326	$ 392,406	MD STRIDE 3 - SVC ONLY - PARK VIEW - 2025 - QUAD L017NW - JANA 108582	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Services affected: 21 estimated EFVs: 21	2708.31 Mitigatable Risk per $10k (Rank #29)	$ 429,193
BCA0303410	303410	$ 392,227	MD - STRIDE 2 - EDWIN ST - 91025 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 466 feet of Bare/unprotected Wrapped Steel main and installed 470 feet of 2" main Services affected: 17 estimated EFVs: 17	Risk/Leak Based (#84 Rank)	$ 309,500
BCA0309316	309316	$ 388,922	MD STRIDE 3 - MAIN & SVC - VERMONT AVE/QUAD Q004NE - JANA 106499 - PG	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Prince George's County	Replaced 49 feet of Vintage Mechanically Coupled Steel main, replaced 26 feet of Contingent Main and installed 570 feet of 2" main Services affected: 31 estimated EFVs: 30	3150.76 Mitigatable Risk per $10k (Rank #18)	$ 723,799
BCA0301525	301525	$ 386,374	MD STRIDE 2 - LEXINGTON DR ~ 68306 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 495 feet of Bare/unprotected Wrapped Steel main and installed 530 feet of 2" main Services affected: 10 estimated EFVs: 10	Risk/Leak Based (#20 Rank)	$ 263,600
BCA0303370	303370	$ 383,613	MD - STRIDE 2 - RANDOLPH ST - 62320 - PG	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Prince George's County	Replaced 493 feet of Bare/unprotected Wrapped Steel main and installed 500 feet of 2" main Services affected: 17 estimated EFVs: 17	Risk/Leak Based (#58 Rank)	$ 312,400
BCA0307079	307079	$ 381,122	MD - STRIDE 3 - BROOKLAWN CT - JANA 87656 - MO	Distribution	PROGRAM 3: Vintage (1952–1956 and 1962–1965) Mechanically Coupled Main and Services with affected services	Montgomery County	Replaced 335 feet of Vintage Mechanically Coupled Steel main and installed 425 feet of 2" main Services affected: 11 estimated EFVs: 10	Risk/Leak Based (#11 Rank)	$ 289,529
BCA0303292	303292	$ 380,859	MD - STRIDE 2 - SUTHERLAND RD - 67366 - MO	Distribution	PROGRAM 2: Bare and Targeted Unprotected Steel Main and affected services	Montgomery County	Replaced 630 feet of Bare/unprotected Wrapped Steel main, replaced 27 feet of Contingent Main and installed 655 feet of 2" main Services affected: 13 estimated EFVs: 13	Risk/Leak Based (#11 Rank)	$ 441,900
TOTAL		**$ 93,302,818**							

STRIDE Capit

Project ID	Actual Cost per STRIDE Reconciliation Filing Attachment G ($) *(Includes Cost of Removal)*	Difference (Actual minus STRIDE Filing Estimated Cost) ($)	Total Actual vs STRIDE Filing Estimate (%)	List Year	Risk Model	Risk Mitigated per $10K (Y/N)	Explanation of difference between Actual Cost per STRIDE Reconciliation Filing Attachment G and STRIDE Estimated Cost >20%
BCA0309171	$ 3,468,577	$ (187,899)	-5.1%	2025	JANA	Y	N/A
BCA0307732	$ 1,751,276	$ (80,178)	-4.4%	2024	Combined Risk Ranking of LP Zones	N	N/A
BCA0303411	$ 1,679,147	$ 374,647	28.7%	2023	Optimain DS	Y	Construction required field changes due to site conditions not aligning with design which resulted in the installation of an additional 148 feet of main and one additional service. The main installation along Meem Avenue and Chestnut Street was realigned to avoid conflicts with existing utilities and to maintain the required clearance per City of Gaithersburg right-of-way inspector. These changes incurred additional costs for traffic control, material, saw cutting, trucking, dump fees, and restoration. Paving required an additional 22,276 SF of Mill and Overlay to meet City of Gaithersburg specifications. Thermoplastic striping was required during the restoration process which resulted in 1,290 LF. This project had an allocation variance due to timing and other considerations.
BCA0307730	$ 1,631,715	$ 243,110	17.5%	2024	Combined Risk Ranking of LP Zones	N	N/A
BCA0301520	$ 1,644,473	$ (32,127)	-1.9%	2023	Optimain DS	Y	N/A
BCA0305244	$ 1,599,656	$ 263,956	19.8%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303337	$ 1,422,460	$ 905,960	175.4%	2023	Optimain DS	Y	Construction required a field change during the main installation process that resulted in the installation of an additional 80 feet of main. The tie-in point at the intersection of Annapolis Road and 64th Avenue was extended in order to abandon an additional section of main due to the condition of the pipe. This change incurred additional costs for labor, materials, traffic control, saw cutting, materials, trucking, and temporary restoration. The main installation was performed at night per request of the State Highway Administration right-of-way inspector resulting in additional spend for light towers, and traffic control personnel and devices. Concrete, asphalt breakage, and vacuum excavating equipment was required during the main and service installation due to 30" thick roadway subsurface (concrete) along Annapolis Road. Also, shoring was required at the tie-in points due to the depth of existing main. An additional 11,850 SF of Mill and Overlay was required to meet Prince George's Specifications and Standards for Road and bridges. This project had an allocation variance due to timing and other considerations.
BCA0307729	$ 1,379,924	$ 283,100	25.8%	2024	Combined Risk Ranking of LP Zones	N	This project had incurred an allocation variance due to timing and other considerations.
BCA0307081	$ 1,244,121	$ 302,121	32.1%	2024	JANA	Y	During the main installation process the use of specialized equipment (hoe ram) resulted in additional expenditures for subsurface pavement breakage. Also, one additional service was affected by the job scope and required full-length replacement incurring additional costs for material, trucking, saw cutting, and traffic control. Shoring was also required at tie-in points due to the depth of the existing main. Project also had additional paving, and timing and other considerations, as well as allocation variance.
BCA0305263	$ 1,366,561	$ 850,661	164.9%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	Seven additional service replacement on Norbeck Road. The main along Norbeck Road was found to be in excess of 10 feet deep. As a result, shoring, vacuum excavation equipment and additional traffic control devices and personal were required to execute these service replacements. Paving required 16,689 LF of Thermoplastic striping during the restoration process resulted in additional cost. This project had an allocation variance due to timing and other considerations.
BCA0304183	$ 1,305,356	$ 288,656	28.4%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	Multiple service replacements required the use of vacuum excavating equipment due to existing main depth and utility conflicts. Two service replacements required larger than estimated service installations due to commercial load requirements. One service required a field change to reroute the service to the back of the building to safely move meter outside and tie-into existing houseline. These changes resulted in additional spend for material, saw cutting, shoring, trucking, soft and hard restoration, and traffic control. Three commercial services required additional traffic control personnel and measures for safety and location of existing services. Six locations required carpentry work during the service replacement process. Four locations required private utility locates. Also had an allocation variance due to timing and other considerations.
BCA0296356	$ 1,261,389	$ (29,311)	-2.3%	2023	Optimain DS	Y	N/A
BCA0303467	$ 1,269,117	$ 371,817	41.4%	2023	Optimain DS	Y	One additional service was added to the scope of work due to an extension in the planned tie-in point which resulted in a full length service replacement and another was added upon field verification of the service location that was affected by the project which required full length replacement resulting in additional cost for material and trucking. Five service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. An additional 23,530 SF of Mill and Overlay was required to comply with Montgomery County requirements whenever two transverse patches are located within two hundred feet (200') of one another along with 1,360 LF of Thermoplastic Striping. These changes have resulted in increased paving costs. Also had an allocation variance due to timing and other considerations
BCA0307068	$ 1,222,082	$ 81,154	7.1%	2024	JANA	Y	N/A
BCA0303343	$ 1,193,148	$ 237,448	24.8%	2023	Optimain DS	Y	Construction required a field change during the main installation process that resulted in an additional 53 feet of 2" plastic main, 80 feet of 4" plastic main and one full length service replacement. The tie-in point at Oakford Place and Greenbrier Drive was extended to the intersection to tie-into the existing 2" plastic main along Greenbrier Drive. The tie-in point at the intersection of Ashford Road and Dale Drive was extended due to the condition of the existing 4" main. These changes incurred additional costs for labor, traffic control, saw cutting, materials, trucking, dump fees, and restoration. Paving required an additional 15,270 SF of Mill and Overlay to meet Montgomery County specifications. This project had an allocation variance due to timing and other considerations.
BCA0307070	$ 1,195,107	$ 38,257	3.3%	2024	JANA	Y	N/A

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BCA0303349	$ 1,222,590	$ (122,710)	-9.1%	2023	Optimain DS	Y	N/A
BCA0299428	$ 1,155,446	$ 121,146	11.7%	2023	Optimain DS	Y	N/A
FPT0000082	$ 1,111,106	$ 548,206	97.4%	2022 &2023	TIMP Risk Model and SME risk analysis input	N/A	Contractor bid included an assumed depth of existing facilities based on available information. Upon excavation facilities were deeper than anticipated. Additionally, extensive rock was encountered during the excavation. Also, changes to the traffic control measures from the approved traffic control plans due to unforeseen on-site factors led to costs beypond those estimated.
BCA0303372	$ 1,111,106	$ 142,606	14.7%	2023	Optimain DS	N/A	N/A
BCA0303389	$ 1,097,547	$ (49,153)	-4.3%	2023	Optimain DS	N/A	N/A
BCA0303478	$ 1,061,690	$ 324,190	44.0%	2023	Optimain DS	Y	Multiple field changes were required during the main installation process due to site conditions not aligning with design, resulting in an additional 69 feet of main to be installed. These changes incurred additional charges for traffic control, materials, saw cutting, trucking, and restoration. Two service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. This project was estimated for asphalt base but was found to be concrete base, resulting in an additional cost. An additional 2,350 SF of Mill and Overlay and Petromat installation was required to meet Montgomery County specifications. This project had an allocation variance due to timing and other considerations.
BCA0304241	$ 1,042,458	$ 295,358	39.5%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	A field change was required during one service replacement to avoid conflict with the retaining wall. This change resulted in an additional 63 feet of pipe to be installed. Vacuum excavating equipment was required at one location due to conflict with existing utilities. Multiple locations required shoring due to the depth of the main and private utility locates due to work occurring in commercial properties. Four locations required separate abandonment holes due to the realignment of the service installations. Paving required an additional 7,038 SF of Mill and Overlay to meet Montgomery County Specifications. 4,715 LF of Thermoplastic Striping was required during the restoration process. This project had an allocation variance due to timing and other considerations.
BCA0304223	$ 1,047,196	$ 310,496	42.1%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	Five service replacements required carpentry work during the meter installation process. One service replacement required the removal of an existing tree and the planting of a new tree. One service replacement required the use of specialized equipment due to conflict with existing landscaping. Four locations required the use of shoring. An additional 38,700 SF of Mill and Overlay was required to meet Montgomery County's specification "cuts within 200' of another must be Milled and Overlaid between them". There was 2990 SF of base asphalt on Gainsborough Rd. that had 50% additional thickness. There was 19,100 LF of thermoplastic striping required. This project had an allocation variance due to timing and other considerations.
BCA0305245	$ 1,031,992	$ 50,892	5.2%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0305264	$ 980,405	$ 101,105	11.5%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303288	$ 988,759	$ 146,159	17.3%	2023	Optimain DS	Y	N/A
BCA0303412	$ 1,058,488	$ 216,288	25.7%	2023	Optimain DS	Y	Construction required multiple field changes during the main installation process that resulted in an additional 100 feet of main to be installed due to site conditions not aligning with design. This change resulted in additional charges for material, traffic control, saw cutting, trucking, and restoration. Vacuum excavating equipment was utilized during the main installation process due to existing utility conflicts. Four service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. Shoring was required at multiple locations due to the depth of the existing main. An additional 2,030 SF of Mill and Overlay and an additional 49 SF of concrete restoration was required. This project had an allocation variance due to timing and other considerations.
BCA0306197	$ 993,329	$ 239,329	31.7%	2024	Leak/quad Analysis discussed in DR 1 - 7	N	One service replacement required vacuum excavation due to the existing main being deeper than anticipated. One service replacement required the use of additional traffic control personnel and devices due to work occurring on a multi-lane roadway in a high traffic area. Paving required an additional 900 SF of Mill and Overlay to meet Prince George's County specifications. Asphalt base and surface asphalt were missed for a parking lot repair to replace a service. There was also an annual cost increase over the estimated costs for all items, especially the base ands Mill and Overlay. This project had an allocation variance due to timing and other considerations.
BCA0307071	$ 1,065,131	$ 100,913	10.5%	2024	JANA	Y	N/A
BCA0301522	$ 988,244	$ 64,644	7.0%	2023	Optimain DS	Y	N/A
BCA0309824	$ 986,311	$ 55,707	6.0%	2025	Field Assessment by Field Operations	N	N/A
BCA0310514	$ 1,000,724	$ 314,212	45.8%	2025	JANA	Y	Multiple field changes. Nine service replacements required the use of vacuum excavation and shoring due to the existing main being deeper than anticipated. Additionally, traffic control saw additional costs due to three of the nine replacements occurring on heavily congested roadways which required extensive traffic control setups. Three service replacements required new installation paths to avoid conflicts with driveways, storm drains, retention ponds, and existing underground utilities. These field changes resulted in an additional 578 feet of service piping to be installed and increased costs for material, trucking, saw cutting, and temporary restoration. This project had an allocation variance due to timing and other considerations.
BCA0303408	$ 987,267	$ 244,967	33.0%	2023	Optimain DS	Y	The use of vacuum excavating trucks were required during the saw cutting process to avoid slurry entering nearby bioswale. Specialized equipment (hoe ram) was required during the main installation process for the excessive subsurface rock. Also, additional traffic control personnel and devices were required due to work occurring at the intersection of a multi-lane state highway roadway. Additionally, shoring was required at tie-in points due to the depth of the existing main. The paving and restoration had additional costs due to the need to repair approximately 1,870 square feet of existing subbase and the installation of 594 linear feet of pavement marking to meet state highway roadway standards and vendor contract increase. This project had an allocation variance due to timing and other considerations.

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FPT0000050	$ 926,004	$ (1,127,863)	-54.9%	2023 & 2024	SME risk analysis input performed by 3rd party	N/A	N/A
BCA0303340	$ 952,368	$ (123,232)	-11.5%	2023	Optimain DS	N/A	N/A
BCA0303377	$ 927,084	$ 87,984	10.5%	2023	Optimain DS	N/A	N/A
BCA0305254	$ 926,004	$ 215,404	30.3%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	Due to five commercial replacements that services required the use of vacuum excavating equipment and additional traffic control personnel and devices due to night work which was requirements by the State Highway Administration right-of-way inspector. The services also incurred additional costs for material, saw cutting, trucking, restoration and private utility locates. Six service replacements required more carpentry work than anticipated related to meter relocations from inside a finished space to outside. This project had an allocation variance due to timing and other considerations.
BCA0304174	$ 951,748	$ 133,048	16.3%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303311	$ 879,564	$ 442,764	101.4%	2023	Optimain DS	Y	Multiple field changes during the main installation process. The tie-in point on Everett Street was extended approximately 250' due to the condition of the existing pipe. The tie-in along Cedar Lane was extended approximately 100' due to a conflict with the sidewalk. These changes incurred additional costs for saw cutting, trucking, and material. Due to the main extensions, four additional services were affected by our replacement project and required replacement. Shoring was required at all tie-in locations. Specialized equipment was utilized during the main installation process. The additional project scope required an additional 925 SF of base. This along with the Montgomery County's specification "cuts within 200' of another must be Milled and Overlaid between them" resulted in an additional 17,500 SF of Mill and Overlay. There was 4,690 LF of thermoplastic striping required. This project had an allocation variance due to timing and other considerations.
BCA0303346	$ 890,729	$ 363,129	68.8%	2023	Optimain DS	Y	Construction required a field change during the main installation process that resulted in an additional 122 feet of main and five service replacements due to the site conditions not aligning with the design. This change incurred additional costs for traffic control, materials, trucking, dump fees, and temporary restoration. Vacuum excavating equipment was utilized during the excavation around trees. Six service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. Multiple locations required shoring due to the depth of the existing main. This project had an allocation variance due to timing and other considerations.
BCA0303934	$ 989,729	$ 192,218	24.1%	2024	JANA	Y	A field change was required during the main installation process, resulting in an additional 65 feet of main to be installed due to the condition of the main and conflict with existing utilities. This change incurred additional charges for materials, traffic control, saw cutting, trucking, vacuum excavating equipment and restoration. Shoring was required at multiple locations due to the depth of the existing main. Two service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. There was an allocation variance on this project due to timing and other considerations.
BCA0303469	$ 867,144	$ 144,344	20.0%	2023	Optimain DS	Y	During the execution of the project an additional 123 feet of main was installed at the intersection of Timberline Road and Northcrest Drive. This change incurred an additional spend for labor, materials, saw cutting, traffic control, trucking, dump fees, and restoration. Seven service replacements required separate abandonment holes due to field conditions. Four service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. There was also an allocation variance on this project due to timing and other considerations.
BCA0304242	$ 835,617	$ 6,617	0.8%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0307069	$ 851,737	$ 101,969	13.6%	2024	JANA	Y	N/A
BCA0300125	$ 854,485	$ 134,885	18.7%	2023	Optimain DS	Y	N/A
BCA0307749	$ 864,397	$ (366,062)	-29.8%	2025	Combined Risk Ranking of LP Zones	N	N/A
BCA0303293	$ 821,750	$ (68,950)	-7.7%	2023	Optimain DS	Y	N/A
BCA0304212	$ 816,292	$ 130,392	19.0%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303338	$ 1,089,218	$ 388,618	55.5%	2023	Optimain DS	Y	A field change due to the condition of the pipe at the intersection of Bluhill Road and Goodhill Road resulted in 31 feet of additional 4" pipe and 2 plastic valves to be installed. This change incurred additional costs for traffic control, saw cutting, materials, trucking, and restoration. Shoring was required at a tie-in location due to the depth of the existing main. Two service replacements required more carpentry work than anticipated related to meter relocations from inside a finished space to outside. This project had an allocation variance due to timing and other considerations.
BCA0300111	$ 800,443	$ 71,743	9.8%	2023	Optimain DS	Y	N/A
BCA0292811	$ 1,742,271	$ 349,387	25.1%	2022	Optimain DS	Y	Additional costs for light towers, and traffic control personnel & devices were required at the intersection of N Summit Ave & E Diamond Ave due to night work requirements by the City of Gaithersburg. Specialized equipment was required at multiple phases of the job including during the main installation along E Diamond Ave due to the excavation of multiple layers of road surface. Specialized equipment was also required at the tie-in point along E Diamond Ave & at two service replacement tie-in points due to the main being located under the pedestrian sidewalk near business entrances and to avoid conflict with the city drainage system. Shoring was required at tie-in points due to depth of main. An additional 31,625 SF of mill and overlay was required to meet Montgomery County's paving specification "cuts within 200' of another must be milled and overlaid between them". Petromat is required to be used within the City of Gaithersburg.

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BCA0303390	$ 784,782	$ 16,682	2.2%	2023	Optimain DS	Y	N/A
BCA0301521	$ 806,509	$ (17,291)	-2.1%	2023	Optimain DS	Y	N/A
BCA0305249	$ 786,633	$ 417,545	113.1%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	There was a change in scope on two commercial services that were originally designed to be abandoned but were replaced full length. This change resulted in the installation of an additional 876 feet of 2" plastic pipe. These changes led to additional spend for traffic control, saw cutting, trucking, material, and labor. Both locations required the use of shoring and vacuum excavating equipment due to depth of existing main. Also, three service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. There was 1141 SF of 12" base and an additional 8,895 SF of Mill and Overlay required to meet Montgomery County Specifications. This project had an allocation variance due to timing and other considerations.
BCA0300122	$ 769,597	$ 184,997	31.6%	2023	Optimain DS	Y	A field change that required the main installation to be extended 125' due to the condition of the existing pipe. This change resulted in additional traffic control, trucking, material, and saw cutting. One additional service was affected and required full length replacement. Multiple locations required the use of shoring due to depth of existing main. Specialized equipment was utilized due to conflicts with existing landscaping and depth of the existing main. In total, there was an additional 2675 SF of Mill and Overlay required to meet Montgomery County's specification "cuts within 200' of another must be Milled and Overlaid between them". Additional asphalt and thermoplastic arrows were required to replace three speed tables.
BCA0307202	$ 809,634	$ 43,265	5.6%	2024	JANA	Y	N/A
BCA0305265	$ 748,106	$ 56,506	8.2%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0306204	$ 726,528	$ 193,692	36.4%	2024	Leak/quad Analysis discussed in DR 1 - 7	N	Primarily due to a commercial service replacement that required excavation across a parking lot during installation. Additional costs for labor, materials, trucking, saw cutting, and restoration. Another commercial service replacement required extensive saw cutting due to site conditions, the property was fully paved with asphalt over a thick concrete base. One service replacement involved installing two-inch plastic piping and required core drilling to tie into the house line. Vacuum excavation was utilized during another service replacement to avoid conflicts with existing utilities. This project had an allocation variance due to timing and other considerations.
BCA0303290	$ 719,656	$ 118,556	19.7%	2023	Optimain DS	Y	N/A
BCA0304240	$ 749,190	$ (9,420)	-1.2%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0305266	$ 722,269	$ 9,469	1.3%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0310515	$ 761,880	$ 60,951	8.7%	2025	JANA	Y	N/A
BCA0305250	$ 734,662	$ (51,538)	-6.6%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303385	$ 705,984	$ 138,984	24.5%	2023	Optimain DS	Y	The tie-in point on Lorain Avenue was relocated due to the condition of the existing main. This change required an additional 30' of main installation and incurred additional costs for material, traffic control, saw cutting, and trucking. Also, a vacuum excavating truck and shoring were required during the main installation process due to the depth of the existing main. Also, four services that were designed as a changeover were changed to full-length replacements due to being black plastic. These services incurred additional costs for material, traffic control, saw cutting, and trucking. This project had an allocation variance due to timing and other considerations.
BCA0309156	$ 674,011	$ 118,571	21.3%	2025	JANA	Y	Paving encountered unforeseen field conditions. This project had an allocation variance due to timing and other considerations.
BCA0309107	$ 720,657	$ (760,866)	-51.4%	2025	JANA	Y	N/A
BCA0303387	$ 668,905	$ 206,205	44.6%	2023	Optimain DS	Y	An additional 19' of main was installed on Colesville Rd due to the condition of the existing main. Also, additional traffic control as well as bagging of parking meters were required to meet the Maryland State Highway roadway requirements throughout the project duration. Additionally, Shoring was required at tie-in locations due to the existing main being in excess of 6' deep. The paving and restoration had additional costs due to the subbase of the existing paving being 12" thick, the requirement of 6,500 linear feet of thermoplastic striping as well as the bagging of meters for paving and restoration. This project had an allocation variance due to timing and other considerations.
BCA0303348	$ 671,875	$ 128,775	23.7%	2023	Optimain DS	Y	During the saw cutting process, a vacuum excavating truck was utilized to avoid slurry from entering a nearby bioswale as well as during the main installation due to the depth of the existing main and conflicts with other utilities. Also, additional traffic control personnel and devices were required for safety due to work occurring at the intersection of a multi-lane state highway roadway. Additionally, shoring was required at tie-in points due to the depth of the existing main. Paving required an additional 1,350 square feet of base and 3,880 square feet of Mill and Overlay because the trench line for the main installation was within 3 feet of the roadway centerline therefore the additional paving was required to meet Montgomery County specifications. The additional paving also required additional pavement marking to meet Montgomery County specifications. This project had an allocation variance due to timing and other considerations.
BCA0301517	$ 663,417	$ 54,017	8.9%	2023	Optimain DS	Y	N/A
BCA0303468	$ 673,612	$ 318,912	89.9%	2023	Optimain DS	Y	A field change was required during the main installation process due to site conditions not aligning with design, resulting in an additional 90 feet of main to be installed and the replacement of two additional services. This change incurred additional spend for material, saw cutting, shoring, trucking, restoration, and vacuum excavation. An additional 4,910 SF of Mill and Overlay was required to meet Montgomery County specifications. Also, 2,860 SF of the sub-base was thicker than normal. There was 2,865 LF of thermoplastic striping required. This project had an allocation variance due to timing and other considerations.

Project ID	Actual Cost per STRIDE Reconciliation Filing Attachment G ($) *(Includes Cost of Removal)*	Difference (Actual minus STRIDE Filing Estimated Cost) ($)	Total Actual vs STRIDE Filing Estimate (%)	List Year	Risk Model	Risk Mitigated per $10K (Y/N)	Explanation of difference between Actual Cost per STRIDE Reconciliation Filing Attachment G and STRIDE Estimated Cost >20%
BCA0303379	$ 648,630	$ 23,530	3.8%	2023	Optimain DS	Y	N/A
BCA0304203	$ 645,241	$ 256,641	66.0%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	Three service replacements required larger than designed piping resulting in additional charges for pipe and backfill material. Five service replacements required carpentry work during the meter installation process. Two locations required the use of specialized equipment to avoid conflict with landscaping. There was also a calculation error on the site-specific paving estimate.
BCA0301278	$ 1,041,148	$ 373,484	55.9%	2022	Leak/quad Analysis discussed in DR 1 - 7	N	Six service replacements required additional traffic control personnel and devices required by State Highway Administration (SHA) and Montgomery County. Six service replacements required carpentry work. Specialized equipment was utilized for one service replacement. This required a drill shot for the service installation and a camera to inspect the sewer laterals before and after installation. Shoring was required at three locations. Additional base was required at multiple locations to match existing thickness. Maryland State Highway Administration required additional mill and overlay limits at all affected locations. This project had an allocation variance due to timing and other considerations.
BCA0310502	$ 702,242	$ (367,447)	-34.4%	2025	JANA	Y	N/A
BCA0309214	$ 628,340	$ 209,321	50.0%	2025	JANA	Y	Primarily driven by a scope increase and jurisdictional requirements. One additional service was affected and required full-length replacement, requiring additional material, trucking, dump fees, and backfill. A revised Traffic Control Plan was required to complete 13 service replacements along Montgomery County roadway. This required the use of additional traffic control personnel and devices to ensure roadway safety and jurisdictional compliance. Two locations required carpentry work during the meter move-out process. This project had an allocation variance due to timing and other considerations.
BCA0304235	$ 639,535	$ 85,035	15.3%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0304243	$ 619,145	$ (13,855)	-2.2%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0307065	$ 612,927	$ (57,295)	-8.5%	2024	JANA	Y	N/A
BCA0300422	$ 623,148	$ 125,548	25.2%	2023	Optimain DS	Y	Site plan discrepancy resulted in an additional 114 feet of main to be installed, this change resulted in additional spend for traffic control, material, saw cutting, trucking, vacuum excavating equipment, dump fees, and restoration. Seven service replacements required more carpentry work than anticipated related to meter relocations from inside a finished space to outside. Paving costs were higher than anticipated due to prevailing wage and materials. This project had an allocation variance due to timing and other considerations.
BCA0305262	$ 606,832	$ 102,432	20.3%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	A field change at Barkwood Drive due to conflict with existing landscaping that required the service to be rerouted and an additional 72' of 3/4 Plastic to be installed. Three locations required separate holes for abandonments. Four locations required carpentry work during the meter installation process. This project had an allocation variance due to timing and other considerations.
BCA0307201	$ 611,571	$ 41,341	7.2%	2024	JANA	Y	N/A
BCA0304193	$ 613,201	$ 197,201	47.4%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	Project spend variance of is due to the utilization of specialized equipment at 4409 54th Place during the service installation process. Multiple locations required the use of shoring due to depth of existing main. An additional 13,000 SF of Mill and Overlay was required during the restoration process. This project had an allocation variance due to timing and other considerations.
BCA0301524	$ 656,958	$ (17,024)	-2.5%	2023	Optimain DS	Y	N/A
BCA0309167	$ 583,494	$ (288,845)	-33.1%	2025	JANA	Y	N/A
BCA0303470	$ 566,501	$ 176,601	45.3%	2023	Optimain DS	Y	Construction required a field change during the main installation process that required an additional 19 feet of main to be installed due to the condition of the pipe. This change resulted in additional charges for materials, saw cutting, trucking, and restoration. Shoring was required at multiple locations due to the depth of the existing main. Vacuum excavating equipment was utilized during the main installation process to avoid conflicts with existing utilities. Four service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. Paving cost came in higher than anticipated due to prevailing wage impacts. Also, an additional 1,694 SF of base and 774 SF of concrete restoration was required. This project had an allocation variance due to timing and other considerations.
BCA0306301	$ 849,747	$ 133,963	18.7%	2024	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0304217	$ 536,988	$ 67,288	14.3%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0299358	$ 533,362	$ (31,838)	-5.6%	2023	Optimain DS	Y	N/A
BCA0305267	$ 524,145	$ (18,955)	-3.5%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0304190	$ 515,174	$ (5,826)	-1.1%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303384	$ 525,066	$ 132,966	33.9%	2023	Optimain DS	Y	Construction required a field change on a service that could not be executed as designed. This change incurred additional costs for material, saw cutting, trucking, and temporary restoration. Shoring was required at multiple tie-in points due to the depth of the existing main. Five service replacements required more carpentry work than anticipated related to meter relocations from inside a finished space to outside. Paving required an additional 815 SF of Mill and Overlay and 1,135 SF of base to meet Montgomery County specifications during the restoration process. This project had an allocation variance due to timing and other considerations.
BCA0304225	$ 499,110	$ (23,390)	-4.5%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0310513	$ 514,376	$ 33,155	6.9%	2025	JANA	Y	N/A

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BCA0304222	$ 513,932	$ (11,568)	-2.2%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303407	$ 491,907	$ 184,807	60.2%	2023	Optimain DS	Y	Construction required a field change during the main installation process that resulted in the main to be realigned at the direction of the right of way inspector to comply with City of Rockville standards for utility clearances per permit requirements. This change resulted in additional costs for traffic control, saw cutting, trucking, dump fees, and restoration. Vacuum excavating equipment was utilized to excavate around existing landscaping. Paving required an additional 5,227 SF of Mill and Overlay to meet City of Rockville specifications and 1,662' LF of thermoplastic striping during the restoration process. This project had an allocation variance due to timing and other considerations.
BCA0305255	$ 514,176	$ 240,576	87.9%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	Due to longer than average service lengths, three commercial service replacements required additional traffic control, private utility locates, and incurred additional costs for material, saw cutting, and temporary restoration. Three service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. Shoring was required at two locations due to the depth of the existing main. An additional 2,285 SF of base and 7,590 SF of Mill and Overlay was required to meet Prince George's specifications. There was an additional 2,326 SF of concrete restoration required. This project had an allocation variance due to timing and other considerations.
BCA0307073	$ 523,594	$ 42,758	8.9%	2024	JANA	Y	N/A
BCA0301282	$ 882,394	$ 359,036	68.6%	2022	Leak/quad Analysis discussed in DR 1 - 7	N	Project spend variance is due to ten commercial service replacements requiring larger diameter piping and longer than average service length. Night work was required at four locations due to work on State Highway roadways. This added additional costs for light towers, and traffic control personnel & devices. Due to site conditions, trenchless technology was utilized for one service replacement. Vacuum excavation was required for one service replacement due to a conflict with retaining wall. This project had an allocation variance due to timing and other considerations.
BCA0305257	$ 498,154	$ 24,454	5.2%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303339	$ 478,741	$ 54,941	13.0%	2023	Optimain DS	Y	N/A
BCA0306230	$ 515,635	$ 109,475	27.0%	2024	Leak/quad Analysis discussed in DR 1 - 7	N	Construction had field changes on five services that required realignments. These services incurred additional costs in materials, saw cutting, trucking, traffic control, and restoration. Also, the abandonment of the existing services required a separate hole. Additionally, the service replacements required more carpentry work than anticipated related to meter relocation from inside to outside. Shoring was required at these locations due to the depth of the existing main. This project had an allocation variance due to timing and other considerations.
BCA0304231	$ 486,472	$ 28,372	6.2%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0304198	$ 519,207	$ 73,107	16.4%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0301509	$ 1,176,831	$ 72,134	6.5%	2022	Optimain DS	Y	N/A
BCA0304226	$ 469,393	$ 104,593	28.7%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	Project spend variance is due to shoring required at multiple locations due to depth of existing main. An additional 10,200 SF of Mill and Overlay was required to meet Prince George's County specification "if two repairs are within 200' of each other, then the area between shall be Milled and Overlaid". This project had an allocation variance due to timing and other considerations.
BCA0304205	$ 480,631	$ (125,169)	-20.7%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0303475	$ 496,349	$ 60,649	13.9%	2023	Optimain DS	Y	N/A
BCA0304216	$ 469,471	$ 27,271	6.2%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0305248	$ 462,114	$ 114,614	33.0%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	One service replacement required the utilizing of vacuum excavating equipment due to conflict with existing utilities. Two apartment complex service replacements utilized private locates. Also, four service replacements required more carpentry work than anticipated related to meter relocation from inside to outside. This project had an allocation variance due to timing and other considerations.
BCA0303341	$ 447,912	$ 103,112	29.9%	2023	Optimain DS	Y	Multiple field changes at tie-in points requiring the main installation to be extended by 50'. Due to the condition of the existing main along Epping Road, the tie-in point was extended 25'. Due to a conflict with a handicap apron, the tie in point along Denley Road was extended 25'. Window cutting was required due to the existing main being inserted. Shoring required at all tie-in points due to depth of main. Specialized equipment was required during the main installation process due to depth of the existing main and to excavate in island. This project had an allocation variance due to timing and other considerations.
BCA0304233	$ 459,809	$ 35,909	8.5%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0304237	$ 460,398	$ (82,950)	-15.3%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A
BCA0310498	$ 542,072	$ (30,010)	-5.2%	2025	JANA	Y	N/A
BCA0301429	$ 1,034,163	$ (46,306)	-4.3%	2022	Optimain DS	Y	N/A
BCA0303476	$ 433,574	$ 219,874	102.9%	2023	Optimain DS	Y	Due to the condition of the existing main, a field change was made at the intersection of Glennon Drive and Seddon Road requiring the main to be extended 28 feet along Seddon Road. Also, vacuum excavation equipment was utilized due to conflicts with existing utilities. Three service replacement locations required carpentry work during the meter relocation installation process. These changes resulted in additional charges for labor, traffic control, trucking, material, shoring, and saw cutting. The paving restoration required an additional 2,460 SF of base and 9,160 SF of Mill and Overlay to meet Montgomery County specifications. This project had an allocation variance due to timing and other considerations.
BCA0304213	$ 441,602	$ 36,802	9.1%	2023	Leak/quad Analysis discussed in DR 1 - 7	N	N/A

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BCA0303376	$ 562,139	$ 52,739	10.4%	2023	Optimain DS	Y	N/A
BCA0307080	$ 467,509	$ (24,386)	-5.0%	2024	JANA	Y	N/A
FPT0000081	$ 857,966	$ 20,853	2.5%	2023 & 2024	TIMP Risk Model and SME risk analysis input	N/A	N/A
BCA0303317	$ 428,961	$ 33,961	8.6%	2023	Optimain DS	N/A	N/A
BCA0309326	$ 427,821	$ (1,372)	-0.3%	2025	JANA	N/A	N/A
BCA0303410	$ 436,453	$ 126,953	41.0%	2023	Optimain DS	Y	This project required the use of vacuum excavating equipment and shoring at multiple locations due to the main being 6 feet deeps. Two service replacements were unable to be installed as designed and incurred additional costs for material, saw cutting, trucking, and restoration. Three services were initially designed as change overs but were determined to be black plastic in the field and became a full-length replacement. These services incurred additional costs for material, saw cutting, trucking, and restoration. This project had an allocation variance due to timing and other considerations.
BCA0309316	$ 450,064	$ (273,735)	-37.8%	2025	JANA	Y	N/A
BCA0301525	$ 414,527	$ 150,927	57.3%	2023	Optimain DS	Y	A field change required the main installation to be extended 60' into the intersection of Brookmoor Drive and the three-way tee to be cut out due to the condition of the existing pipe. These changes resulted in additional spending for traffic control, saw cutting, trucking, and material. Multiple locations required the use of shoring due to depth of existing main. An additional 11,270 SF of Mill and Overlay was required to meet Montgomery County's specification "cuts within 200' of another must be Milled and Overlaid between them". The project tie-in points were both at intersections resulting in additional restoration requirements. This project had an allocation variance due to timing and other considerations.
BCA0303370	$ 417,769	$ 105,369	33.7%	2023	Optimain DS	Y	Construction required a field change during the main installation process that resulted in an additional 33 feet of main to be installed and one additional service. The southern tie-in point along Randolph Street was extended due to a storm drain conflict. This change resulted in additional charges for traffic control, material, trucking, dump fees, saw cutting, and temporary restoration. Paving required an additional 5,973 SF of Mill and Overlay to meet Prince George's County specifications. This project had an allocation variance due to timing and other considerations.
BCA0307079	$ 425,319	$ 135,790	46.9%	2024	JANA	Y	One service replacement required a field change, the service could not be installed as originally designed and resulted in additional costs for saw cutting, material, and restoration. Four service replacements required more carpentry work than anticipated related to meter relocations from inside to outside. Paving and restoration required an additional 3,770 SF of Mill and Overlay to meet Montgomery County specifications. This project had an allocation variance due to timing and other considerations.
BCA0303292	$ 411,400	$ (30,500)	-6.9%	2023	Optimain DS	Y	N/A

TOTAL

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-7

Q. Please refer to Exhibit KMM-02(b), column "Customer Benefits/ Risk Mitigated". Numerous items in this column are of the form "__ __ Projected Leaks per 100 Services" where the "__ __" is a specific pair of numbers for each project.

a. Is there an implied decimal point between the two numbers in each of these projects?

b. Has WGL quantified the benefit to its customers from these projects in any units other than "Projected Leaks per 100 services"?

i. If so:

1. Please provide WGL's quantification of this benefit for each such project in Exhibit KMM-02(b)

2. Please identify the software or analysis tool used to quantify this benefit

3. Please provide a working electronic copy of the software or analysis tool used to quantify this benefit

ii. If not, why not?

c. Over what time frame does WGL expect that the replaced assets would experience "__ __ projected leaks per 100 services"?

d. What are the "projected leaks per 100 services" for the new assets that WGL installed in each of these projects?

WASHINGTON GAS' RESPONSE **February 26, 2026**

A.

a. There should be a decimal point where the two numbers are separated by a space for the numbers listed in that column. The decimal points can be seen on the Excel version of KMM-02(b) which is available on the SharePoint site.

b. Please see the response to OPC Data Request No. 1-1.

c. WGL expects that the replaced assets would experience the number of projected leaks per 100 services over a period corresponding to the pipe's age from installation through 2019.

d. The likelihood of a leak on a new plastic service is close to zero.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

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OPC DATA REQUEST NO. 1

QUESTION NO. 1-9

Q. Please refer to Exhibit KMM-02(b), column "Customer Benefits/ Risk Mitigated", and Witness Murphy's Direct Testimony at page 15, lines 4-5 ("Going forward the Company intends to expand the use of JANA to the extent possible to include this type of risk analysis for all assets."). Regarding risk quantification using JANA:

a. Has JANA provided WGL with a detailed description of the consequence of failure model that WGL uses for risk analysis?

    i. If so, please provide the detailed description that JANA provided to WGL.

b. What types or classifications of consequences does the JANA Lighthouse model allow WGL to model?

c. What types or classifications of consequences does WGL model using the JANA software?

d. Of the risk on assets in WGL's Maryland system, what is the total risk related to consequences of the following types?

    i. Health and safety

    ii. Direct economic loss

    iii. Regulatory impacts

    iv. Environmental impacts

    v. Corporate image or reputation

e. How does WGL's implementation of the JANA model differentiate between consequences associated with leaks and consequences associated with explosion or ignition? What other categorization of consequences does the model require or enable?

f. Of the total risk on assets in WGL's Maryland system, what is the total risk related to consequences of the following event types?

    i. Grade 1 leaks

ii. Grade 2 leaks

iii. Grade 3 leaks

iv. Explosions

v. Ignition events

vi. Where there is overlap among these categories (e.g. a grade 1 leak that is also an explosion), please identify and describe the overlap.

WASHINGTON GAS' RESPONSE **February 26, 2026**

A.

a. Yes. See the Company's response to OPC DR 01-08.

i. The Company is providing the following CONFIDENTIAL attachment with this response, which provides the information requested in subparts (a), (b), (c), and (e): "CN 9849 OPC DR 1-9 Attachment 01 CONFIDENTIAL".

b. Please see CN 9849 OPC DR 1-9 Attachment 01 CONFIDENTIAL

c. Please see CN 9849 OPC DR 1-9 Attachment 01 CONFIDENTIAL

d. The risk related to consequences for each category requested is provided below. Total risk values below, expressed in dollars, are annualized figures.

i. Health and safety: 4,765,275

ii. Direct economic loss: 128,163,044

iii. Regulatory impacts: 146,189,127

iv. Environmental impacts: 19,441,643

v. Corporate image or reputation: 156,276,632

e. Please see CN 9849 OPC DR 1-9 Attachment 01 CONFIDENTIAL

f. The JANA DIMP risk model does not provide a breakdown of risk in these categories. Instead, the model evaluates the likelihood of an individual pipe segment failing, the scenarios that may occur due to a failure (e.g., a Grade 1, 2, or 3 leak), and the potential consequences associated with those scenarios (health and safety implications, property damage, repair costs, and others).

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

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OPC DATA REQUEST NO. 1

QUESTION NO. 1-12

Q. Please refer to Witness Murphy's Direct Testimony at page 14, lines 13-18.

a. What are the units of "likelihood" used in WGL's analysis of risk?

b. What are the units of "consequence" used in WGL's analysis of risk?

WASHINGTON GAS' RESPONSE **February 26, 2026**

A. a. The units of likelihood are annualized and represented as total failures per year.

b. Consequences are represented in dollars.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

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OPC DATA REQUEST NO. 1

QUESTION NO. 1-13

Q. Please refer to Witness Murphy's Direct Testimony at page 14, line 18 through page 15, line 5.

a. What are the units of "risk"?
b. What are the units of "risk reduced per dollar spent"?
c. What was the total estimated risk on WGL's Maryland system:
   i. As of WGL's most recent estimate?
   ii. As of the end of the test year?
   iii. As of the start of the test year?
   iv. As of January 1, 2023?

WASHINGTON GAS' RESPONSE **February 26, 2026**

A.

a. Risk units are dollars, expressing the average annual expected loss (probability times consequences).

b. Risk reduced per dollar spent is the risk of the pipe segment(s) divided by the replacement cost. Therefore, it is a unitless ratio.

c. Please see responses each subpart below:

i. As of WGL's most recent estimate: $454,835,722

ii. As of the end of the test year? $454,835,722

iii. As of the start of the test year? $456,753,266

iv. As of January 1, 2023? JANA was not implemented as of January 1, 2023. See the Company's response to Data Request No. 1-4.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 1

QUESTION NO. 1-20

Q. Please refer to column "Explanation of difference between Actual Cost per STRIDE Reconciliation Filing Attachment G and STRIDE Estimated Cost >20%" in Exhibit KMM-02(b).

a. Please describe in detail how WGL tracked changes in projected project cost and/or scope after project execution began. What approvals are required to proceed with the revised project?

b. Please describe in detail the process that WGL used to determine whether to proceed with or reduce the scope of a project after it becomes clear that it will be more costly to complete than projected.

c. Did WGL take risk reduction per dollar of project cost into account when deciding whether to cancel or re-scope projects after it became clear that they would be more costly to complete than projected?

d. Please identify each example of STRIDE-eligible projects initiated during the period from January 1, 2023, to September 30, 2025, that were cancelled, deferred, or had their scope reduced due to cost increases. For each example, please provide the original estimated cost, the revised estimated cost, and the final disposition of the project.

WASHINGTON GAS' RESPONSE **February 26, 2026**

A.

a. through c. The need for STRIDE project cost or scope changes after the project execution began are often identified by the on-site construction crew working on the

project. These scope changes could be due to project-specific factors that were unknown when the project cost was originally estimated, such as:

- Conflicts with existing utilities
- Poor pipe condition at proposed tie-in location
- Differing site conditions (i.e. retaining walls, inconsistent roadway measurements, existing trees, etc.)
- Night work or extensive traffic control required by permit/jurisdiction
- Additional carpentry required to move the meter outside
- Specialized equipment required due to depth, conflict with other utilities and/or environmental considerations (i.e. bioswale)
- Additional costs associated with shoring, excavation, backfill, etc. due to the depth of main

The on-site construction crew notifies Washington Gas management of the need for cost or scope changes. Washington Gas management reviews the specific project conditions and makes the determination of how to address the unforeseen issues taking into consideration both safety and cost, although risk reduction per dollar of project cost is not recalculated. Any project changes are identified in the field notes, and the as-built construction documentation contains the final assets and locations of those assets. Company management personnel also review and reject or approve all units that were necessary and appropriate for each project prior to payment and provide oversight of the pipeline contractors to verify installation of the facilities per required specifications. This oversight not only promotes safe, quality installations, but also provides thorough oversight of all proposed field design changes and any associated pay items required to complete the work on each project.

d. The Company did not cancel or defer any projects originally submitted on the 2023, 2024, or 2025 STRIDE project lists due to cost and/or scope changes.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
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OPC DATA REQUEST NO. 2

QUESTION NO. 2-1

Q. Refer to Figure 1 on page 5 of Witness Murphy's direct testimony.

a. Please provide the underlying data used to produce this figure.

b. Provide the historical gas plant in service additions by the categories in this figure for each of the last 10 years.

WASHINGTON GAS' RESPONSE **March 02, 2026**

A.

a. See Kevin Murphy's testimony Exhibit KMM-1 page 1-20 for the underlying data used to produce Figure 1 page 5.

b. Figure 1 on Page 5 of Witness Murphy's testimony is a summary of pertinent capital projects according to functional classification. The Company developed Figure 1 over roughly six weeks to provide a visual representation of the investments at issue in its application. The research that would be required to provide the requested 10-years' worth of information in the form reflected in Figure 1 would likewise take in excess of six weeks. For these reasons, the Company is providing the GPIS data for the past ten years broken out by year using standard funding classes as managed in the Company's financial reporting in attachments "CN 9849 OPC DR 2-1 Attachment 01."

CO – SPONSOR (subpart a): Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

CO – SPONSOR (subpart b): Donald Preston II
Manager Fixed Asset Accountingent

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 2

QUESTION NO. 2-2

Q. Refer to the following statement on pages 14-15 of Witness Murphy's direct testimony: "Results from the JANA risk model, combined with non-specific per-unit cost estimates, allow the Company to prioritize assets as candidates for replacement by using a 'risk reduced per dollar spent' metric during its risk mitigation planning."

a. What is meant by "non-specific" in this context?

b. Provide the per-unit cost estimates used to prioritize all assets that were candidates for replacement during the period from January 1, 2023 through September 30, 2025.

WASHINGTON GAS' RESPONSE **March 02, 2026**

A.

a. The Company's use of "non-specific per-unit cost estimates" means that these cost estimates are based on historic averages from past construction work rather than site specific costing. These estimates have not been refined based on engineering review and scoping of the candidate group of assets (bundle), nor do they have site-specific elements.

b. The per-unit cost estimates are included in CN 9849 OPC DR 2-2 Attachment 01 CONFIDENTIAL.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
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OPC DATA REQUEST NO. 2

QUESTION NO. 2-7

Q. Refer to the following statement on page 20 of Witness Murphy's direct testimony: "Throughout the process, the Company continuously analyzes cost-effective options to defer, reduce, or eliminate the need to replace, upgrade, or construct new system components, including an analysis of non-pipeline alternatives, as appropriate."

a. When does the Company consider non-pipeline alternatives "appropriate"?

b. Where in the Capital System Planning Process, as described in Diagram 1 of Witness Murphy's testimony, does NPA analysis occur?

c. During the period from January 1, 2023, through September 30, 2025, how many NPAs did the Company analyze?

i. For each NPA analyzed during the period from January 1, 2023, through September 30, 2025, provide all workpapers, analyses, models, calculations, decision memos, and similar documents, used to analyze the NPA, in working and unlocked electronic format.

WASHINGTON GAS' RESPONSE **March 02, 2026**

A.

a. The Company considers non-pipeline alternatives ("NPAs") appropriate when the NPAs do not negatively impact safety, energy reliability, when the NPAs are cost effective, when there is evidence that the NPAs will lower GHG emissions, and when the NPAs do not impede the Company's obligation to serve.

b. As stated in Witness Murphy's testimony at page 20, the analysis and consideration of NPAs occurs throughout the Company's Capital System Planning Process, which includes in the planning considerations, during the project/program needs identification, when project concepts are initiated, as well as when projects are designed/scoped, when costs are estimated, and when engineering evaluates and authorizes projects.

c. The Company considers several activities and programs as NPAs, such as energy efficiency/ demand response, interruptible rates, local supply/storage, discontinuation of gas service, and proactive abandonments (see Witness Murphy direct testimony, pages 21 to 25). Washington Gas utilized many of these NPAs during the period January 1, 2023, through September 30, 2025, and the Company continuously analyzes and considers NPAs as part of its Capital System Planning Process. Since Washington Gas continuously applies NPAs at a programmatic level, NPAs are not always individually analyzed, and therefore the number of NPAs analyzed cannot be counted.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
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OPC DATA REQUEST NO. 2

QUESTION NO. 2-8

Q. Please describe in detail the Company's process for evaluating projects for NPA suitability from the time the system need first arises until the start of construction. When responding to this question, please provide justification and support (such as completed or planned studies) for each of the following:

a. what criteria make a project suitable for an NPA,

b. the types of NPA solutions/technologies considered,

c. the assessment of costs and benefits of the NPA and other potential solutions,

d. the NPA solicitation process,

e. the customer outreach and education process,

f. the necessary lead-time for NPA implementation

WASHINGTON GAS' RESPONSE **March 02, 2026**

A.

a.–f.

Please see the Company's response to OPC 2-7. The Company's process is grounded in established engineering best practices and standards to determine appropriate materials and components based, in part, on an analysis of their expected useful life, design options, cost, and assessment of available alternatives. This ensures that the Company first considers whether new infrastructure components are needed based on its demand forecasts and its flow modelling analysis (reflecting both forecasted contraction and expansion in consumption, as the case may be), which informs the Company's capital and system planning. Throughout the process, the Company continuously analyzes cost-effective options to defer, reduce, or eliminate the need to replace, upgrade, or construct new system components, including an analysis of non-pipeline alternatives, as appropriate. Underlying this analysis for safety-related investments is consideration of the estimated risk reduction over the project's expected useful life. Therefore, each capital project reflects these

considerations and is chosen because it offered system improvements benefiting customers. Since Washington Gas continuously applies NPAs at a programmatic level, the consideration of NPAs is inherently built into the capital planning process for all infrastructure projects, therefore there is no separate process for evaluating projects for an NPA.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
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OPC DATA REQUEST NO. 2

QUESTION NO. 2-14

Q. Please answer the following questions based on the Company's experience relining pipes:

a. What is the shortest, longest, and average duration of interrupted service customers have experienced as a result of a relining project?

b. Does the Company have to relight customer equipment each time a relining project is complete?

c. Please provide the number and length (ft) of pipelines the Company has relined for each of the last twenty years, broken out by pipe material, relining method, and whatever other subcategories are available (e.g., by leak history, pressure district, etc.).

d. Please provide historical spending on pipe relining for each of the last twenty years broken out by whatever other subcategories are available (e.g., by cost category, leak history, pressure district, etc.).

WASHINGTON GAS' RESPONSE **March 02, 2026**

A.

a.–b.

The Company has only completed lining projects either with no affected customers or where customers were able to be shifted either temporarily or permanently to another facility to maintain their service. For future potential projects, the Company cannot say and notes that the impact of a relining project is fact-dependent (e.g., whether and the extent to which service replacements or transfers are required). Every connected customer will need to be relit if within the scope of a lining project. Should there be no parallel gas main where the services can be temporarily or permanently transferred to avoid customer interruption, a typical customer interruptions during lining operations will range from 7 to 14 days, depending upon the length of the pipe to be lined.

c. The Company has not lined any pipeline on its Maryland distribution system in past twenty years. Also, please see the response to OPC Data Request 2-13 subpart (a).

d. See the response to subpart (c).

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

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WASHINGTON GAS COMPANY RESPONSE
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OPC DATA REQUEST NO. 2

QUESTION NO. 2-19

Q. For the last 10 years, please provide a table showing the number of leaks identified for each year and the number of leaks repaired. Please categorize these leaks by pipe material and by grade of leak.

WASHINGTON GAS' RESPONSE **March 02, 2026**

A. The Company is providing the requested information in attachment "CN 9849 OPC DR 2-19 Attachment 01."

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

Material	2015			2016		
	Grade 1	Grade 2	Grade 3	Grade 1	Grade 2	Grade 3
Cast Iron	17	23	2	18	6	0
Copper	117	66	6	126	67	6
Plastic	722	246	112	755	197	51
Bare Steel	64	156	16	85	90	23
Unknown	25	13	1	24	8	1
Protected Coated Steel	418	436	70	543	387	47
Unprotected Coated Steel	72	113	28	76	50	14

2017			2018			2019		
Grade 1	Grade 2	Grade 3	Grade 1	Grade 2	Grade 3	Grade 1	Grade 2	Grade 3
16	12	0	33	24	1	17	10	1
187	87	11	157	134	5	180	90	5
801	203	24	779	334	30	879	286	43
88	145	9	97	143	7	162	146	7
34	4	0	77	26	7	19	14	1
911	567	42	1152	982	38	1164	923	58
63	64	11	110	102	6	132	95	10

2020			2021			2022		
Grade 1	Grade 2	Grade 3	Grade 1	Grade 2	Grade 3	Grade 1	Grade 2	Grade 3
11	13	4	12	6	3	8	8	1
153	107	9	124	69	11	109	39	5
800	279	60	769	198	60	725	156	54
94	133	32	70	67	13	90	74	12
14	6	5	22	5	0	13	2	0
913	831	124	975	583	61	712	384	70
65	75	5	83	49	5	63	34	4

2023			2024		
Grade 1	**Grade 2**	**Grade 3**	**Grade 1**	**Grade 2**	**Grade 3**
7	2	3	9	5	1
108	28	2	149	22	3
687	93	24	591	89	28
63	64	9	46	44	7
15	2	0	169	53	15
494	286	58	536	248	34
59	40	5	40	13	1

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

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WASHINGTON GAS COMPANY RESPONSE
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DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 6

QUESTION NO. 6-1

Q. Please refer to Diagram 1 ("Capital System Planning Process") on page 12 of Witness Murphy's Direct Testimony

a. Please identify the step(s) in this planning process where project or program down-selection occurs. That is, which steps act as filters between potential capital investments and investments that pass a hurdle or threshold to proceed.

b. For each step identified in part (a) to this question, please identify the hurdle or threshold used to select projects or programs to proceed.

i. Please describe each hurdle or threshold in detail.

ii. Please provide examples of the documentation, forms, or templates used when evaluating projects or programs against the hurdle or threshold.

c. For each step identified in part (a) to this question, please identify the role (held by an individual or group) responsible for making the determination regarding whether to advance a project or program to later stages of the process.

WASHINGTON GAS' RESPONSE **March 06, 2026**

A.

a. Project or Program "down selection" (defined as deferring or eliminating a capital investment) would occur throughout the life cycle as additional information is available, but typically would occur primarily in the Initiation ("Initiate Project/Program Concept"/ "Customer / 3rd Party Request") or Preliminary Design/Scoping ("Design Project/Program Scope"/"Develop Project Program Cost Estimate") or Authorization ("Funding Projects") steps. These steps are inherently intended to develop the proposed capital project and ultimately conclude with a decision to proceed with authorizing funding or not.

b. Hurdles or thresholds are specific to the individual program or project asset and the considerations that apply to the identified need. The Company notes that the JANA risk model is currently utilized for risk based distribution main and service replacements and is in the process of being implemented for other asset categories

i. Examples:

- STRIDE has a defined method for risk ranking and prioritization based on targeting of the highest priority projects as determined by JANA and the risk reduced per dollar spent metric. Given that STRIDE projects are targeted at higher risk system assets, STRIDE projects are selected in rank order until sufficient work is identified to align with approved STRIDE expenditures.
- New business projects are evaluated using the process described in the Company's Commission-approved tariff P.S.C. Md. No. 6 ("tariff"), General Service Provision No.14.
- Third party relocations are evaluated using the process described in the Company's tariff General Service Provision ("GSP") No. 15 and any applicable stipulated in ROW agreements or locality requirements.
- Work governed by compliance obligations are assessed relative to the specific obligation.

ii. Examples of documentation, forms, or templates used:

1. STRIDE prioritization (risk reduced per dollar spent) – refer to Case No. 9849, Attachments provided with the Company's responses to OPC 1-3 and 1-6.

2. New Business Acceptance (GSP 14 evaluation), see Attachment OPC 6-1 provided with this response for an example

    a. Customer commitment letter for BCA 294308

3. Third Party Relocation Authorization/Work Order agreement

c. By area (as it relates to gas carrying infrastructure projects):

- **Initiation** ("Initiate Project/Program Concept" / "Customer / 3rd Party Request")

    i. Customer/third-party requests are moved forward in the process upon intake of the request by the Company's new business or engineering teams
    ii. Initiate Project/Program Concepts are typically identified or initiated out of the Asset Management, Engineering & Gas Supply Operations business unit.

- **Preliminary Design/Scoping** ("Design Project/Program Scope"/"Develop Project Program Cost Estimate")

    i. This activity is typically performed by the Engineering team for a specific project or Program development.

- **Authorization** ("Funding Projects")

    i. The final review/authorization is made on planned gas carrying infrastructure replacement projects consistent with approved budget and in alignment with Company signing authority policies.

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

Washington Gas
A WGL Company

Gas Service Installation Contribution Payment Quote and Customer Agreement Terms and Conditions

Business Case Project Number: 294308
Business Case Project Name: SouthLakes, Bowie MD
Date of Quote: June 7, 2021
Agreement Expiration Date: December 7, 2021
Contribution Payment Quote: $0.00

Washington Gas Responsibilities:

1. Marking of all existing underground utility-owned lines by Miss Utility.
   IMPORTANT NOTE: Customer is responsible to ensure that all privately-owned underground lines on the property are marked before construction begins. (e.g. underground sprinkler systems, propane lines, customer owned electric lines, septic systems, etc.)
2. Installation of any and all necessary gas mains, services and meter(s) to serve your project.
3. Site restoration activities as required, e.g. lawn seeding and straw, sidewalk/paving repairs, etc.

Customer Responsibilities:

1. Marking of all privately-owned underground lines on the property prior to construction (e.g. underground sprinkler systems, customer owned propane and/or electric lines, septic systems, etc.
2. Ensuring construction site is within 6” of final grade prior to gas service line installation.
3. Removal of all debris and other hindrances from the gas line installation area.

Scheduling:

After receipt of this signed agreement and contribution payment, Washington Gas will approve your project and begin the process of obtaining the required construction permits from the applicable permit agency. After permits are received, a Washington Gas underground contractor will contact you to schedule your installation.

Contribution Payment Due:

Contribution payments must be made in full upon return of the signed agreement. Payments can be made via the electronic payment links below or by downloading, executing and returning this agreement along with a money order or check. Please make checks payable to Washington Gas and return to Washington Gas, c/o Sales Operations, 6801 Industrial Road, Springfield, VA 22151.

Agreement Expiration or Job Modification Clause:

Upon expiration of this contribution quote or any customer-requested modification to job design, including but not limited to, gas load requirements, construction installation route, etc., or upon expiration of this original quote, may result in the re-evaluation of Washington Gas’ capacity to serve your project and/or a financial re-evaluation of the project using current construction prices at the time of re-evaluation.

AGREED AND ACCEPTED:

I have reviewed the terms and conditions specified above related to the extension/installation of facilities to provide natural gas service to my project/premise and hereby agree to such terms and conditions.

Signature _____ Date _____

Print Name _____

EXECUTIVE SUMMARY

PROJECT NAME:	MD - AOP - BILLABLE AT 100% - 700 PROGRESS WAY– MO CO
PROJECT DESCRIPTION:	Install 62' of 4"PLA-20# Abandon 35' of 4"PLA-20#
BCA#:	**310137**
WORK REQUEST NO:	**4060653**
LENGTH:	62 feet
NO. OF SERVICES:	-
NECESSITY:	Main gas line in conflict with proposed electric transformer.

PROJECT

- Matan ,the owner of 700 Progress Way buildings has been working on a fit-out development project of the shell warehouses at this site. Their proposed plan requires a new electric transformer to serve their fit-out project. This new installment is in direct conflict with the existing 4"PLA- 20#.
- Washington Gas's existing 4"PLA gas main will need a relocation to avoid the conflict with the electric transformer. To accommodate the gas usage required by the buildings and avoid the conflict with the proposed utility, a total of 62 feet of 4"Pla needs to be relocated along 700 Progress Way.
- The estimated cost for this relocation is **$83,830** based upon the final design and applying contractor unit rates. This cost was provided and approved by PM team on 11/13/2024.
- **Buch Construction, Inc.** has elected not to self-perform any construction tasks as stated in the WOA and cost estimate breakdown.
- This project was budgeted within the CY2025 AOP Replacement Budget.
- The project is 100% Billable, funded by BUCH, Construction Inc. A payment of **$83,830** was received on 01/23/2025.
- Gas relocation is expected to start by beginning of March 2025.

Developer Project Point of Contact:

Emily Gallagher, PE
Project Manager
Kimley-Horn
989-390-6634 (Cell)
emily.gallagher@kimley-horn.com

Side A
BCA#310137
WR#4060653
01/08/2025

WORK ORDER ISSUED TO WASHINGTON GAS
BY BUCH CONSTRUCTION, INC.

This "Work Order Agreement" is between Washington Gas and Buch Construction, Inc. (Requestor)

1. **JOB LOCATION**:
   - 700 Progress Way, Gaithersburg, MD 20879
2. **WORK BENEFIT CLAUSE:**
   - All the work is being performed by Washington Gas, or its authorized subcontractor, at the request of Buch Construction, Inc and all Washington Gas costs and expenses will be reimbursed by Buch Construction, Inc.

3. **LAST AND FINAL OPTION CLAUSE**:
   - Buch Construction, Inc has exhausted all options to avoid the conflict with the Washington Gas lines and is now requesting the gas line relocation as the final option.

4. **WORK TO BE DONE BY WASHINGTON GAS AND WHY**:
   - Install approximately 62' of 4" plastic gas due to conflict with proposed electric facilities.
   - Abandon approximately 35` of existing 4" plastic main.

5. **TIMING REQUIREMENTS FOR WASHINGTON GAS WORK**:
   - Construction will be scheduled once design is complete, the necessary jurisdictional permits have been obtained, Miss Utility requirements are met, and Washington Gas has received a signed Work Order Agreements and a check for the amount described below.

6. **WASHINGTON GAS IS RESPONSIBLE FOR:**
   - Planning and designing the gas main relocation plans based from plans provided by Buch Construction, Inc via Kimley Horn dated 07/30/2024.
   - Staking proposed gas lines and providing trench depth information.
   - Disconnecting and purging main to be abandoned.
   - Installation and inspection of new gas main.
   - Tie-in of relocated gas lines to existing gas lines.
   - Backfilling and compaction to meet Washington Gas specifications.
   - Temporary trench cut restoration after all work is complete
   - Final paving, landscaping and/or surface restoration of the project area.

7. **BUCH CONSTRUCTION, INC IS RESPONSIBLE FOR**:
   - Providing clear access to the site where the job needs to be done.
   - Performing final grading within the work area, certifying the grades are "final", such that WGL can proceed with installing the new gas main to assure a minimum of 36" of final cover measured from top of gas pipe to top of grade) is achieved. The intent is that WGL will leverage the final grades when installing the gas main to assure proper depth.
   - Certifying the alignment both vertical and horizontal of the new (relocated) gas main, prior to WGL introducing gas and placing the facility into service. The intent is to resolve any alignment issues prior to backfilling and placing the gas main into service.
   - Protection of gas pipeline during their construction activity and liability for any damage to gas facilities during their construction activity.
   - Removal and disposal of any remaining abandoned gas main that may conflict with any proposed construction.
   - If differing conditions or complexities are encountered during construction Section 9 – "Deviation Payment Clause" will be applied.
   - The terms specified on the other side (Side B) of this agreement.

8. **PAYMENT:**
   - Buch Construction, Inc will reimburse Washington for the actual cost of the work under Washington Gas' purview.
   - The estimated cost of the gas main relocation project is $83,830. The estimate is valid for 30 calendar days from the date provided at the top of this contract and is subject to change after the 30-day period.
   - Washington Gas charges include materials, company labor, design and inspection with standard overhead charges and required federal tax payments.
   - Should actual costs be less than or exceed $83,830 the required federal tax payments will be adjusted accordingly.

9. **DEVIATION PAYMENT CLAUSE:**
   - In the event that deviations occur such as but not limited to:
     1) Change in the Plans
     2) 3rd party intervention
     3) Differing site conditions as a result of Buch Construction, Inc performed task
     4) Extreme weather conditions
     5) Additional footage requires relocation
     6) Unexpected environmental issues
     7) Additional contract provisions and rates Washington Gas has with it contractors
     8) Requested expedited work
     9) For such reasons listed above but not limited to the charges will accrue until job is completed.

Washington Gas, at its option, will submit a contract addendum to cover such additional costs. Washington Gas will submit the addendum for authorization and signatures before work will continue. Washington Gas will issue a final bill once the project is completed.

10. TIMING OF PAYMENT:

- Payment of $83,830 is due in advance of start of work.
- If costs are less than $83,830 the difference will be refunded after Washington Gas sends the final invoice.
- If costs are greater than $83,830 , Washington Gas will be reimbursed for the difference within 30 days.

PROPOSED BY:
Buch Construction, Inc
8155 Westside Blvd,
Fulton, MD 20759

Brian Dribben
Project Executive

1/16/2025
(Date)

ACCEPTED BY:
Washington Gas Light Company
6801 Industrial Road
Springfield, VA 22151

Kevin Murphy
VP Asset Management,
Engineering & GSO

agm 1/23/25

BCG 1/24/25

01/27/2025
(Date)

Side B

I. **WGL SERVICES.**
A. Definition. The term "services" wherever appearing herein means all or portion of the work necessary to accomplish the work described hereon.
B. Performance. WGL shall perform services set forth on side A of this work order. The methods by which WGL carries out and implement services shall be within WGL's sole discretion, unless noted.

II. **PRICE AND PAYMENTS.** Requestor shall pay WGL for WGL's services according to the pricing agreement specified on side A, Item 8: Payment. Requestor has or will provide a deposit to WGL in the amount set forth on side A, Item 10: Timing of Payment. The payment of this deposit shall be made according to the stated terms contained in the work order. This deposit shall be credited toward the last payment due to WGL for services provided.
WGL shall submit invoices upon completion of all services specified. However, at WGL's option, invoices for partial completion maybe submitted on a monthly basis. Requestor shall pay the invoices within 30 days of receipt. Commencing on the thirty-first day after submission of the invoice, unpaid sums due WGL shall bear interest at the rate of ½% per month until paid. Requestor shall be liable for any reasonable attorney's fees and cost incurred by WGL arising out of the institution and prosecution of any legal proceedings brought by WGL as a result of the Requestor's breach of this Agreement, including Requestor's failure to pay for services.

III. **WARRANTIES.**
A. Authorizations. Requestor warrants that it holds such licenses, certifications, and authorizations as are required to perform services under this Agreement. WGL will obtain such permits as are set forth.
B. Survival. All the warranties made by Requestor shall survive the termination of this Agreement.

IV. **INDEMNITY.** During the term of this work order and thereafter, Requestor will indemnify WGL, its directors, officers, and employees, agents and servants for, and hold each of them harmless from, actual or threatened harm caused by or arising out of any improper, negligent, or wrongful act or omission of Requestor, or its employees in connection with the undertaking or performance of services under this Agreement. The term "harm" as set forth in the preceding sentence, includes any and all (1) claim, suits, or legal proceedings; (2) damages or injuries; (3) interest; (4) costs, expenses, or fees, including cost associated with investigating and defending any claims, suits or legal proceedings, and including reasonable attorney's fees attributable to such investigation or defense or attributable to enforcing the provisions of this Agreement; and (5) loss of profits;

V. **RELATIONSHIP OF PARTIES.** WGL is an independent contractor and this Agreement is not, and shall no be construed as an agreement of partnership, joint venture, or employment between WGL and Requestor or between WGL and any of Requestor's subcontractors.

VI. **LIENS.** Requestor shall not file, or permits its directors, officers, employees, agents, servants, or independent contractors to file any lien for labor or materials against any WGL facilities or equipment, or against WGL.

VII. **REMEDIES.**
A. Failure to Commence Work. WGL will begin and complete services on the dates specified in the work order. In the event of circumstances beyond WGL's control, WGL may at its discretion, with notice to Requestor, change the start and completion dates. In the event that WGL fails to perform the services specified under this Agreement in a timely fashion, the sole remedy available to requestor shall be the return of any monies already paid to WGL by the Requestor. Requestor and its agents and assigns, specifically waive in advance and hereby release WGL from any cause of action arising out of WGL's failure to commence the work except an action for return of monies already paid to WGL by Requestor.
B. Unacceptable Conditions at Job Site. If WGL should determine that conditions at the job site are not in compliance with applicable laws, regulations, permit or easement conditions, safety practices or other requirement of this Agreement, WGL may, in its discretion, stop work until the conditions at the job site are brought into compliance by the Requestor with the applicable requirements. If Requestor does not bring conditions into compliance within a reasonable time, WGL may, in its sole discretion, cancel this Agreement upon oral notice to Requestor, or retain another entity to remedy the conditions referred above. In such event, Requestor shall be liable to WGL for the reasonable value of the services actually performed by WGL and for such additional costs as may be incurred by WGL or third entity in remedying the unacceptable condition. "Reasonable value" means the actual or estimated cost incurred by WGL through the time when WGL ceased services.
C. No Damage for Delay. Washington Gas and its contractors shall not be liable for any damages that may occur from delays.

VIII. **GENERAL PROVISIONS.**
A. Cancellation Generally. This Agreement maybe cancelled by either party at any time, without cause, upon 30 days' written notice to the other party before WGL provides service under this Agreement. Any cancellation of this Agreement shall not relieve the parties from any obligations they have, whether imposed by this Agreement or by law, arising out of any acts, omissions, or transactions occurring before the effective date of cancellation.
If bankruptcy proceedings are commenced by or against either of the parties, or either is adjudicated a bankrupt, or a receiver of either is appointed and qualifies, then either of the parties may cancel this Agreement by giving three days' written notice to the other party.
B. Integration of Agreement. This instrument constitute the entire Agreement between parties relating to the work to be performed, and no statement, promise, or inducement made by either party or agent of either party which is not contained in this Agreement shall be valid or binding. This Agreement and the scope of services as set forth in the work order hereunder may not be changed except in writing signed by the parties. In the event of conflict between this Agreement and work order, the language of this Agreement shall be controlling.
C. Severability. If any part, term, or provision of this Agreement is specifically held by a court or arbitration panel to be illegal or in conflict with any applicable law, the validity of the remaining portions or provisions shall not be affected, and the rights and obligations of the parties shall be construed and enforced as if the Agreement did not contain the particular part, term, or provision so held to be illegal or in conflict.
D. Nonassignability. Except for assignment by WGL there shall be no assignment of this Agreement, nor of any interest in this Agreement, except upon written consent of the party against which such assignment or delegation would, in the absence of this provision, be effective.
E. Waiver. No waiver of any breach of this Agreement shall be held to be a waiver of any other or subsequent breach. Notwithstanding anything in this Agreement to the contrary, all rights, remedies, and warranties afforded in this Agreement shall be taken and construed as cumulative, that is, in addition to every other right, remedy, or warranty provided herein by law.
F. Headings. The clause headings appearing in this Agreement have been inserted for the purpose of convenience and ready reference. They do not purport to, and shall not be deemed to, define, limit, or extend the scope or intent of the clauses to which they pertain.
G. Good Faith. The parties are charged with the duties of acting in good faith, or being fully cooperative with one another, and using their best efforts to reach agreement on any matters to be resolved during the term of the Agreement, to meet the specific terms of the Agreement, and to perform all acts necessary or incidental hereto.
H. Notices. All notices under this Agreement shall be in writing, and shall be sent by first class mail, postpaid to the parties at the addresses noted on side A.
I. Effective Date. This Agreement shall be effective as of the date of first written above and shall supersede all prior agreements between the parties, which are hereby cancelled, provided that all projects begun or contracted for prior to the effective date of this Agreement shall be completed under the terms of the agreement in effect at the time construction was begun or the contract executed.
J. Binding Effect. This Agreement shall insure to the benefit of, and be binding upon, the heirs, executors, administrators, assignees (if the nonassignability provision is waived), and successors of the respective parties.

-- END OF SIDE B --

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
DIRECTED TO THE OFFICE OF PEOPLE'S COUNSEL

OPC DATA REQUEST NO. 6

QUESTION NO. 6-3

Q. Please refer to Diagram 1 ("Capital System Planning Process") on page 12 of Witness Murphy's Direct Testimony

a. Describe in detail the inputs to the Capital Budget Process (grey area with dashed border) from sources other than the Capital System Planning Process. For example, are there inputs from corporate finance, investor relations, AltaGas corporate leadership, engineering, human resources, operations, maintenance, or other components of WGL's organization?

b. Please identify the documentation provided into the Capital Budget Process, and who (by role) provides each document.

c. Who conducts the "Review of Projects Submitted to Budget"?

d. How does WGL sets its aggregate capital budget for each year?

e. What are the limits set on the capital budget, and who sets them?

f. Is the aggregate Capital Budget set before or after projects are submitted and reviewed?

WASHINGTON GAS' RESPONSE **March 06, 2026**

A.

a. Most of the inputs in the annual Capital Budget Process source from the processes shown in Diagram 1 in Witness Murphy's testimony. Those in turn source from WGL's Operations groups (of which Witness Murphy is a part).

Additional inputs include the following:

1. Anticipated New Customer volumes sourced from the Company's Customer Experience group.

2. Filings on accelerated replacement programs, which specify projected program funding (e.g. STRIDE).

3. IT capital projections, including both software and hardware. This may include assumptions around whether software projects are cloud-based or on-premise solutions.

4. Estimates on facilities capital projects, provided by the WGL Facilities group.

5. Strategic business development opportunities sourced from WGL's Business Development group.

b. Documentation would source from the processes listed in Diagram 1 and noted in subpart (a). Individual roles as to who provides capital budget information will vary year-to-year based on what projects are projected.

c. The Review of Capital is lead by Company Witness Murphy, in conjunction with the Senior Vice-President, Capital Delivery. Other members of senior management may be included depending on the nature of projects.

d. The Company's capital budget in each year is allocated by its board of directors as part of an overall assessment of capital needs and plans.

e. There are no explicit limits beyond the amount noted in subpart (d). The Company's capital budget is approved by the board of directors as noted in Diagram 1.

f. The aggregate capital budget is set before the full list of projects are submitted and reviewed. Certain projects or programs may be underway or in development at the time the aggregate capital budget is approved, but the full list of projects is not completed until afterward.

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Vice President, Asset Management, Engineering and Supply

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OPC DATA REQUEST NO. 8

QUESTION NO. 8-2

Q. For each of the following projects (BCAs) listed in Exhibit KMM-02(b), please provide WGL's contemporaneous documentation of each alternative considered to the project that was executed.

a. BCA0303337
b. BCA0303346
c. BCA0309171
d. BCA0303311
e. BCA0303468
f. BCA0305263
g. BCA0305249
h. BCA0305255
i. BCA0301282
j. BCA0304203

WASHINGTON GAS' RESPONSE **March 12, 2026**

A.

All ten BCAs referenced replaced small diameter main (6" and smaller) with affected services or replace scattered services under STRIDE Programs 1 and 3.

BCA No. 309171 was evaluated as per the Company's NGEA Compliance Filing, attached as "CN 9849 OPC DR 8-2 Attachment 01."

The other nine (9) of the ten (10) BCAs requested above were submitted on the CY 2022 and CY 2023 STRIDE Project List, prior to the Next Generation Energy Act ("NGEA") and did not require explicit documentation of the alternatives considered.
Service-only replacement projects involved pipes in sizes ranging from ½" to 2". No affected customer requested their gas service to be abandoned. In these instances, cost

effective replacement alternatives, including cured-in place lining (CIPL) techniques, are not available. Hence, these services were replaced with new plastic pipes either through direct bury or insertion methods.

The main and service projects involved services in sizes described above connected to 6" diameter and smaller mains, with multiple service connections. No customer requested their gas service to be abandoned. CISBOT (robotic cast iron joint repair) was not feasible because it is applicable to cast iron pipes only with sizes 12" and greater. In addition, these smaller diameter bare steel mains were not suitable for the CIPL technique due the number of customers connected to them who would need suffer an extended outage during the entire lining process. Therefore, the conventional replacement methods were utilized, in which main and services were replaced with new plastic pipes through direct bury or insertion.

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OPC DATA REQUEST NO. 10

QUESTION NO. 10-3

Q. Please refer to Attachment 1 to WGL's response to OPC Data Request 1-8. This attachment appears to be section 1 of a larger document.

a. Please identify the larger document of which this attachment is a part.
b. Please provide the larger document of which this attachment is a part.

WASHINGTON GAS' RESPONSE **March 13, 2026**

A.

a. This is a section of a confidential document titled "J-DIMP Risk Model Report, Addendum A: Likelihood of Failure Model Description."

b. The Company is providing "CN 9849 OPC DR 10 – 3 Attachment 01 CONFIDENTIAL."

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OPC DATA REQUEST NO. 10

QUESTION NO. 10-5

Q. Please refer to WGL's response to OPC Data Request 1-7(d) ("The likelihood of a leak on a new plastic service is close to zero.").

a. Does WGL also believe that the likelihood of a leak on a new plastic main is close to zero?
b. Does this response (for mains or services) include leaks due to excavation damage?
c. Does WGL believe that the risk of excavation damage to plastic pipe is close to zero?
   i. If not, what risk does WGL assign to excavation-related leaks on new plastic mains or services?

WASHINGTON GAS' RESPONSE **March 13, 2026**

A.

a. Yes. The likelihood of a leak on a new plastic main is one to two orders of magnitude less than that of piping targeted for replacement.
b. Yes.
c. Yes. The likelihood of a leak on any given new plastic main segment is near zero, and this includes risk attributable to third party damage threats.

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OPC DATA REQUEST NO. 11

QUESTION NO. 11-1

Q. Please refer to WGL's response to OPC Data Request 1-9, including part (f) and Attachment 1, and Data Request 1-8, part (e).

a. Of the risk on assets in WGL's Maryland system, what is the total risk related to events of the following types of threats:
   i. Corrosion
   ii. Equipment
   iii. Excavation Damage
   iv. Incorrect Operations
   v. Joint/Fitting Failure
   vi. Material Failure
   vii. Natural Force Damage
   viii. Other Outside Forces
   ix. Other Failure Mode

b. OPC Data Request 1-9 Attachment 1, page 2, describes five scenarios for each threat type. Figure 1 on that page shows how the risk of each scenario is calculated separately, for each threat.

   i. For each threat type (e.g., those listed in the previous part of this question, or whatever breakdown is used in the JANA software), please provide the cumulative risk on WGL's Maryland system, for each of the five scenarios coupled with that threat type.

   ii. For each of the five scenarios, please provide the cumulative risk on WGL's Maryland system corresponding to the occurrence of that type of scenario.

WASHINGTON GAS' RESPONSE **March 13, 2026**

A.

a. Total risk, on an annual basis are as follows:
   i. Corrosion: 83,495,071
   ii. Equipment: 22,315,456
   iii. Excavation Damage: 65,474,156
   iv. Incorrect Operations: 6,726,663
   v. Joint/Fitting Failure: 241,771,058
   vi. Material Failure: 5,312,645
   vii. Natural Force Damage: 26,654,888
   viii. Other Outside Forces: 2,923,682
   ix. Other Failure Mode: 162,105

b.
   i. The risk model output used by the Company does not break down risk information in the requested format. While the JANA DIMP model calculates the risk associated with each of the scenarios in the referenced event tree and sums the calculated risk of those scenarios, model output includes only the sum of the overall risk for each threat. The information provided in subpart (a) above represents the format of the information available.

   ii. Please see the response to subpart (i); the model does not provide results in this format.

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OPC DATA REQUEST NO. 11

QUESTION NO. 11-2

Q. Please refer to WGL's response to OPC Data Request 1-9, Attachment 1.

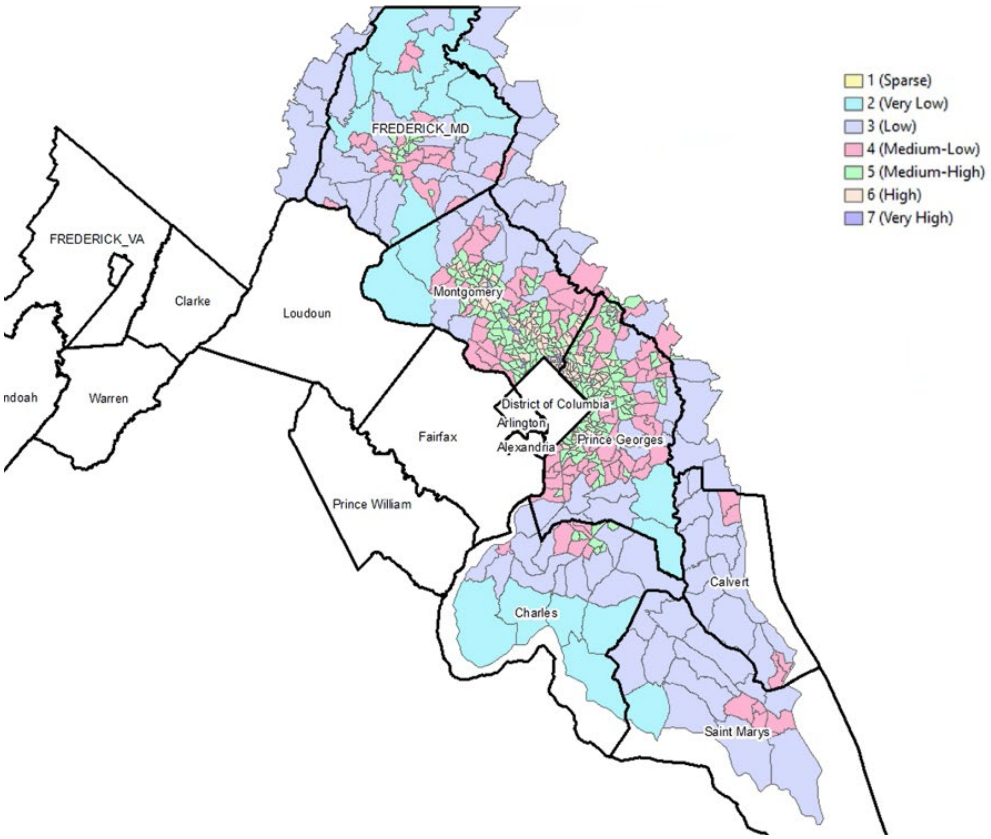
a. Please provide a map of WGL's Maryland service territory showing which areas are classified into each location class (1 through 7). Please provide this map in GIS shapefile format if available.

b. Of WGL's Maryland customers, how many are located in areas classified into each location class (1 through 7).

c. Of WGL's Maryland mains, how many miles are located in areas classified into each location class (1 through 7).

WASHINGTON GAS' RESPONSE **March 13, 2026**

a. Please see the requested map below.



b. It would require a special study to derive exact customer counts, but the Company can provide an approximation with information readily available in the risk model by reporting the number of services within each location category. The table provided for part (c) below provides a count of the number of services within each location category.

c. Please see the table below.

Location Category	Count of Services	Miles of Main
1 (Sparse)	0	0
2 (Very Low)	1,445	31
3 (Low)	42,789	887
4 (Medium-Low)	117,271	1,908
5 (Medium-High)	196,510	2,463
6 (High)	87,258	995
7 (Very High)	8,499	127

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OPC DATA REQUEST NO. 11

QUESTION NO. 11-3

Q. Please refer to WGL's response to OPC Data Request 1-9, Attachment 1. Page 9 of this attachment states "The following sections detail the impact consequences for each of these five scenarios as the maximum dollar figure of cost per incident."

a. Please confirm that WGL uses the maximum cost per incident when calculating risk, rather than the average cost per incident. If denied, please explain what WGL uses and how it was derived.

b. Has WGL estimated the average dollar figure of cost per incident for any combination of scenario, location category, and type of consequence (that is, for any value shown in Tables 5 through 9 of this attachment)?

i. If so, please provide WGL's estimate(s).
ii. If not, why not?

WASHINGTON GAS' RESPONSE **March 13, 2026**

A.

a. The Company discussed this section with the JANA Corporation for further clarification. The Company understands the values are averages that represent discrete, expected loss based on a statistical analysis of historical industry incident data. They do not represent maximum costs or historic worst-case scenarios.

b. Within the context of the risk model, no. These parameters were developed in tandem with JANA's input and are only intended to provide a general magnitude of the different consequences that may occur due to a failure in the distribution system.

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OPC DATA REQUEST NO. 11

QUESTION NO. 11-5

Q. Please refer to WGL's response to OPC Data Request 1-9, Attachment 1, Figure 2.

a. For each category in the right-hand-most column of this figure (i.e., beginning with Injuries), please identify the entity or entities that would incur the costs quantified by WGL's parametrization of these consequences. For example, property damage costs could be incurred by property owners whose property is damaged by the event, and response and repair costs could be incurred by WGL.
b. For each category in part (a) where WGL incurs some cost, please state whether that cost would be recovered from ratepayers as part of the cost of service under WGL's current regulatory regime in Maryland.

WASHINGTON GAS' RESPONSE **March 13, 2026**

A. The purpose of the JANA DIMP risk model is not to determine the entities that would be responsible for the costs of damages associated with these consequences and therefore responsibility has not been delineated. The purpose of the model is to produce a probabilistic risk assessment of the Company's distribution system in accordance with 49 CFR192 Subpart P (which establishes the DIMP requirements). The risk model, and the parameters within it, are not suited for use in any context outside of integrity management.

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OPC DATA REQUEST NO. 12

QUESTION NO. 12-1

Q. Please refer to Attachment 1 to WGL's response to OPC Data Request 1-9. For each of the five tables in Section 2.3 of this document (corresponding to scenarios 1 through 5), please provide all documents, resources, workpapers, analyses, and models used to determine or develop the values presented in the table in each category below. Please provide these materials in working and unlocked electronic format.

i. No. of injuries
ii. No. of fatalities
iii. Property damage
iv. Response cost
v. Commodity loss
vi. Service loss
vii. Regulatory cost
viii. Environmental cost
ix. Reputation cost

WASHINGTON GAS' RESPONSE **March 17, 2026**

A. Except for property damage, the calculations for these values are embedded within the JANA risk modeling software. They are proprietary and not available in a readily shareable format. The values are generally derived by a review of historic natural gas incidents reported to PHMSA and the consequences associated with those incidents.

Estimated property damage values were provided to the JANA risk model by Washington Gas and are discussed in the Company's response to OPC DR 12-5.

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OPC DATA REQUEST NO. 13

QUESTION NO. 13-1

Q. Please refer to Witness Murphy's Direct Testimony at page 36, lines 3-11.

a. Please define the term "cost-effective" as used in this context.

b. Has WGL quantified the annual or cumulative expected revenues associated with customers served by any of the pipes referred to in this section?

i. If so, please provide the revenue quantification analysis, documentation, and workpapers used to develop the expected revenues.

ii. If not, why not?

WASHINGTON GAS' RESPONSE **March 18, 2026**

A.

a. Cost effective refers to delivering value relative to the cost to obtain it. See also the Company's response to OPC DR 1-14.

b. No. STRIDE projects are performed to address system safety and reliability, and to comply with various regulations, including the obligation to serve.

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OPC DATA REQUEST NO. 15

QUESTION NO. 15-1

Q. Regarding leak detection, response, and repair:

a. How many leaks, by grade, did WGL identify in the test year in Maryland?

b. How many leaks, by grade, did WGL respond to in the test year in Maryland?

c. How many leaks, by grade, did WGL repair in the test year in Maryland?

d. How many leaks, by grade, did WGL address through replacement during the test year in Maryland?

WASHINGTON GAS' RESPONSE **March 24, 2026**

A.

a.

Leak Grade	**Count**
Grade 1	1,473
Grade 2	468
Grade 3	91

b. This would be the same count as the number of leaks identified, requested in part (a).

c. The Company notes that, because leak management is necessarily reactive in part (as distinct from the Company's integrity management program proactive replacements) a leak may be "resolved" by repair initially to make the situation safe and/or to allow the Company to perform the appropriate replacement. Please see the table below for leaks resolved.

Leak Grade	Count of Leaks Resolved
Grade 1	1,480
Grade 2	478
Grade 3	100

d. The Company notes that, because leak management is necessarily reactive in part (as distinct from the Company's integrity management program proactive replacements) a leak may be "resolved" by repair initially to make the situation safe and/or to allow the Company to perform the appropriate replacement.

Accordingly, the following table identifies the number of leaks resolved initially by replacement and also those that were repaired initially then replaced where readily identifiable in work order comments. Therefore, this likely underestimates the number of replacements necessary or initiated due to a leak. The Company notes that a more detailed analysis would require a special study:

Leak Grade	Estimated Replacements Resulting From Leaks
Grade 1	121
Grade 2	19
Grade 3	1

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OPC DATA REQUEST NO. 15

QUESTION NO. 15-4

Q. What was WGL's total test year operations and maintenance cost for repairing leaks (not including response or replacement costs)? Please provide this cost broken out by account (operations, maintenance, mains, services, etc.). Please provide the value for Maryland only.

WASHINGTON GAS' RESPONSE **March 24, 2026**

A.

The following table summarizes the test year O&M cost for leak repairs (excluding response and replacement costs) broken out by category for Maryland.

	Cost for leak repairs ($MM)
Maintenance of Mains	$2.7
Maintenance of Services	$6.0
Maintenance Supervision and Engineering*	$1.8
TOTAL**	**$10.5**

*Represents the entire Maintenance Supervision and Engineering expense in the test year, a portion of which is related to leak repairs. The Company does not track Maintenance Supervision and Engineering expenses for leak repair separately.

**The total cost does not reflect the cost to repair above ground leaks. The Company does not track the costs as requested.

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MARYLAND PUBLIC SERVICE COMMISSION

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DIRECTED TO THE OFFICE OF STAFF COUNSEL

STAFF DATA REQUEST NO. 8

QUESTION NO. 8-9

Q. Please provide explanation about the benefits of New Business or Growth capital expenditures to the existing WGL gas customers?

WASHINGTON GAS' RESPONSE **March 09, 2026**

A.

As explained in Exhibit KMM-03, existing customers benefit from New Business/Growth capital investments due to the ability to spread fixed utility costs over a larger customer base and higher throughput. New customers are required to provide a contribution in aid of construction (CIAC) if the net present value of the expected revenues from the customer does not cover the cost to connect the new customer, as set forth in General Service Provision #14 of the Company's tariff. This is designed to insulate existing customers from any increased costs associated with serving new customers.

Additionally, it is important to note that responsiveness to such requests is central to the Company's ongoing obligation to serve.

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Vice President, Asset Management, Engineering and Supply

MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

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DIRECTED TO THE OFFICE OF STAFF COUNSEL

STAFF DATA REQUEST NO. 8

QUESTION NO. 8-21

Q. Please provide the information requested in the table below, Maryland total leaks eliminated/repaired during the years CY 2021 – 2025:

Total Leaks Eliminated/Repaired during the Year
2021 - 2025

Year	Mains	Services	System Leaks at End of Year Scheduled for Repair
2021			
2022			
2023			
2024			
2025			

WASHINGTON GAS' RESPONSE **March 09, 2026**

A.

Total Leaks Eliminated/Repaired during the Year
2021 - 2025

Year	Mains	Services	System Leaks at End of Year Scheduled for Repair
2021	880	1,648	194
2022	723	1,382	126
2023	563	1,112	134
2024	748	1,306	210
2025	736	1,216	126

SPONSOR: Kevin M. Murphy, PE
Vice President, Asset Management, Engineering and Supply

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OPC DATA REQUEST NO. 1

QUESTION NO. 1-2

[redacted]

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OPC DATA REQUEST NO. 1

QUESTION NO. 1-6

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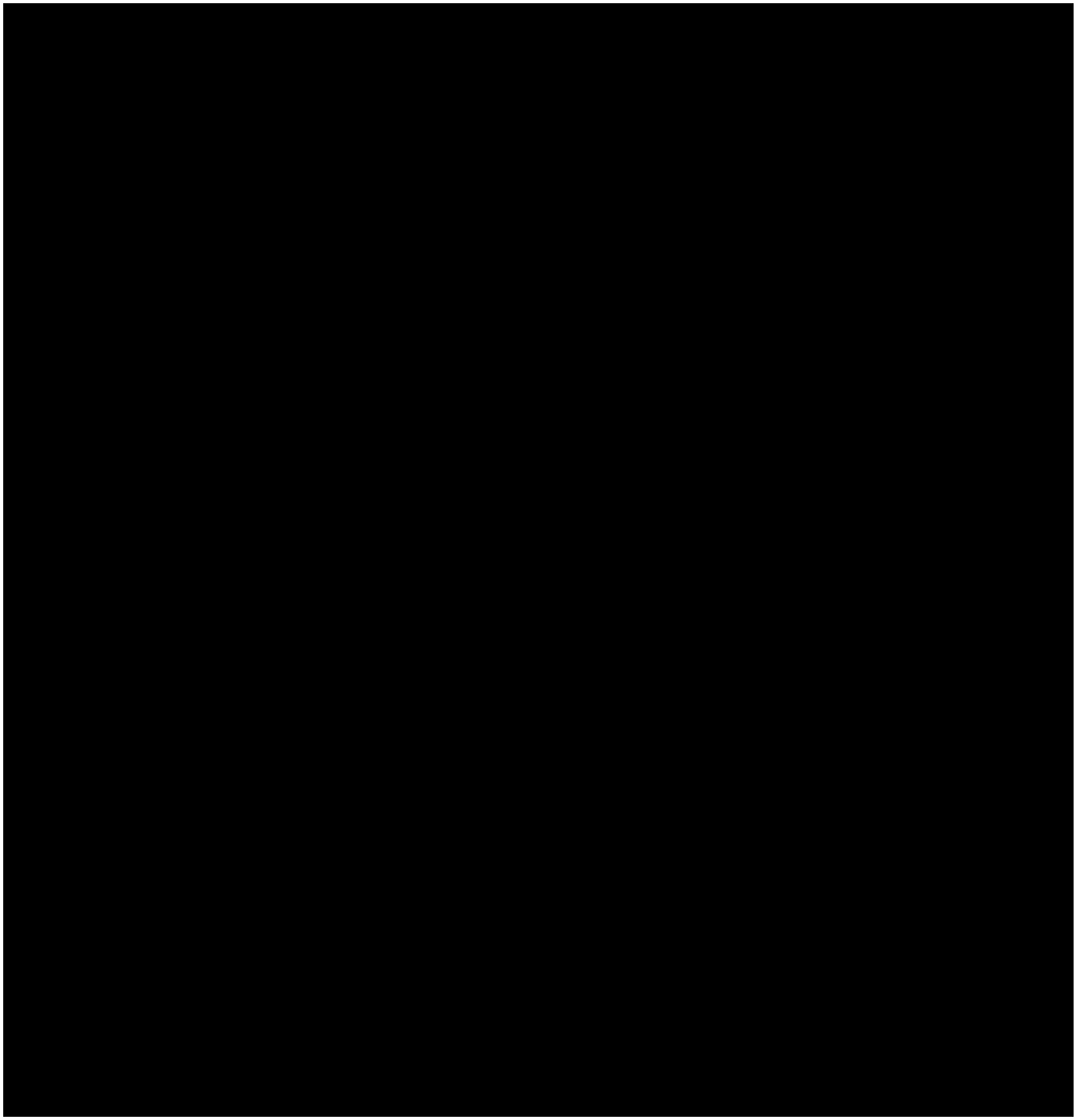

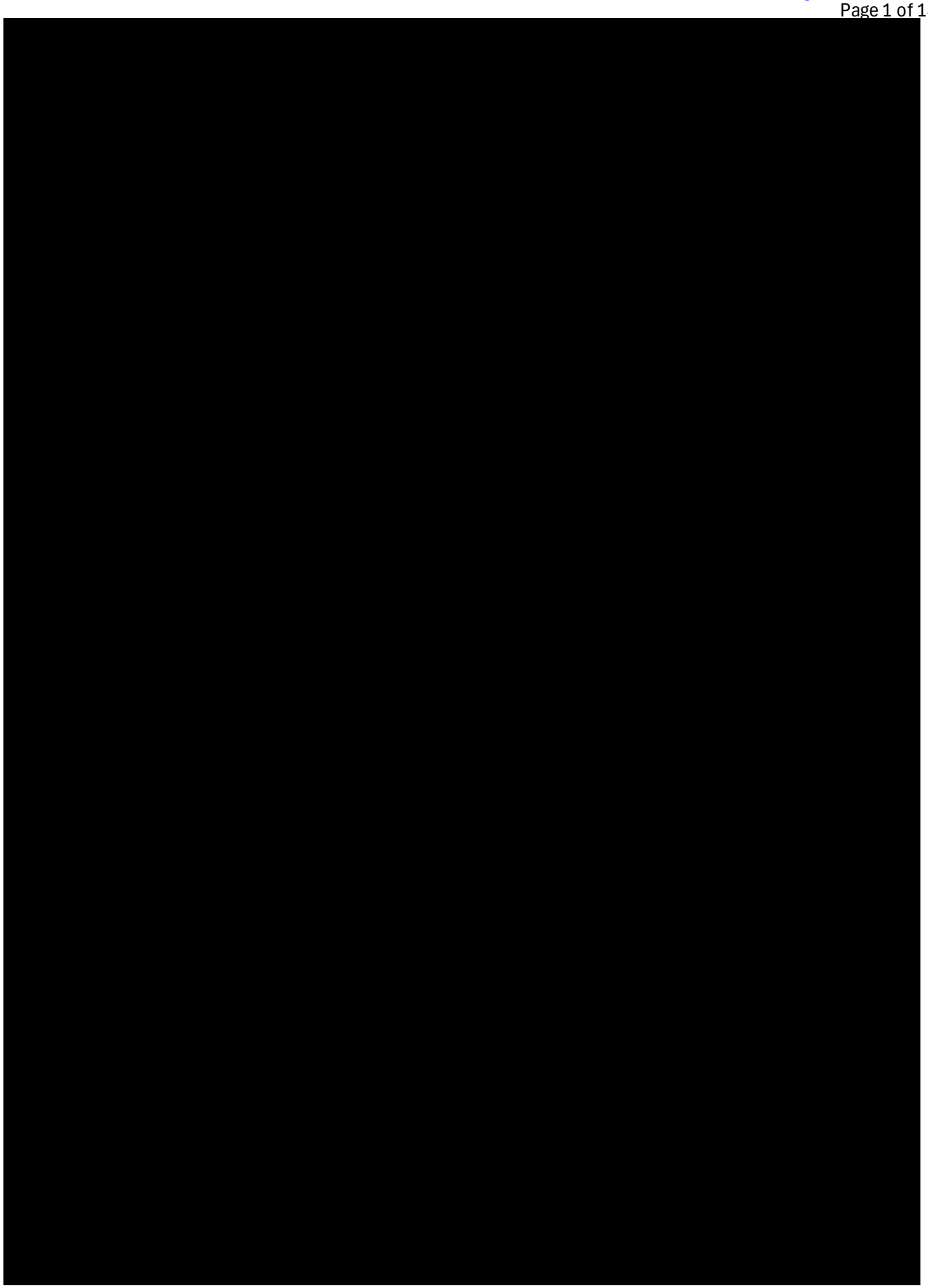

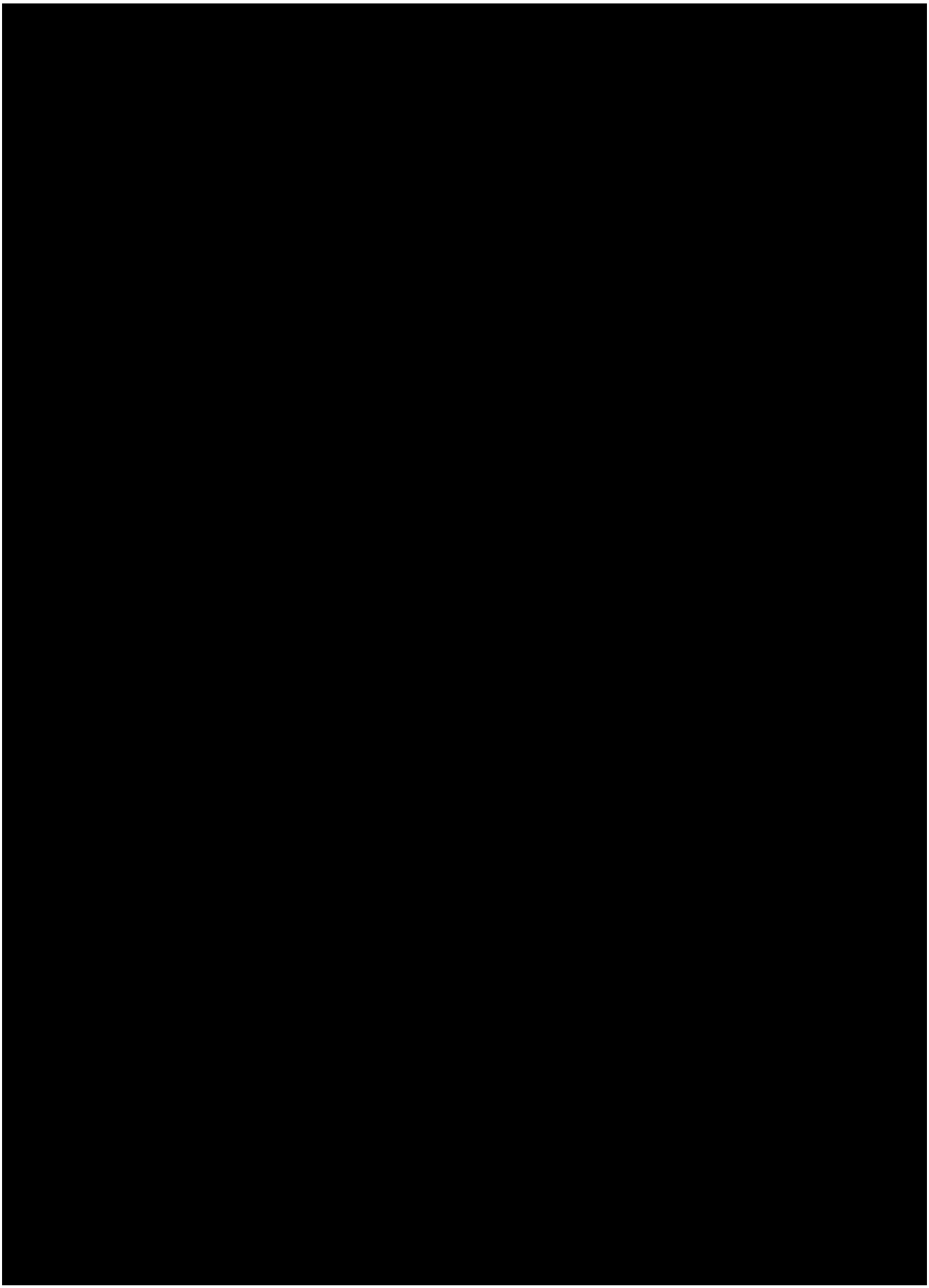

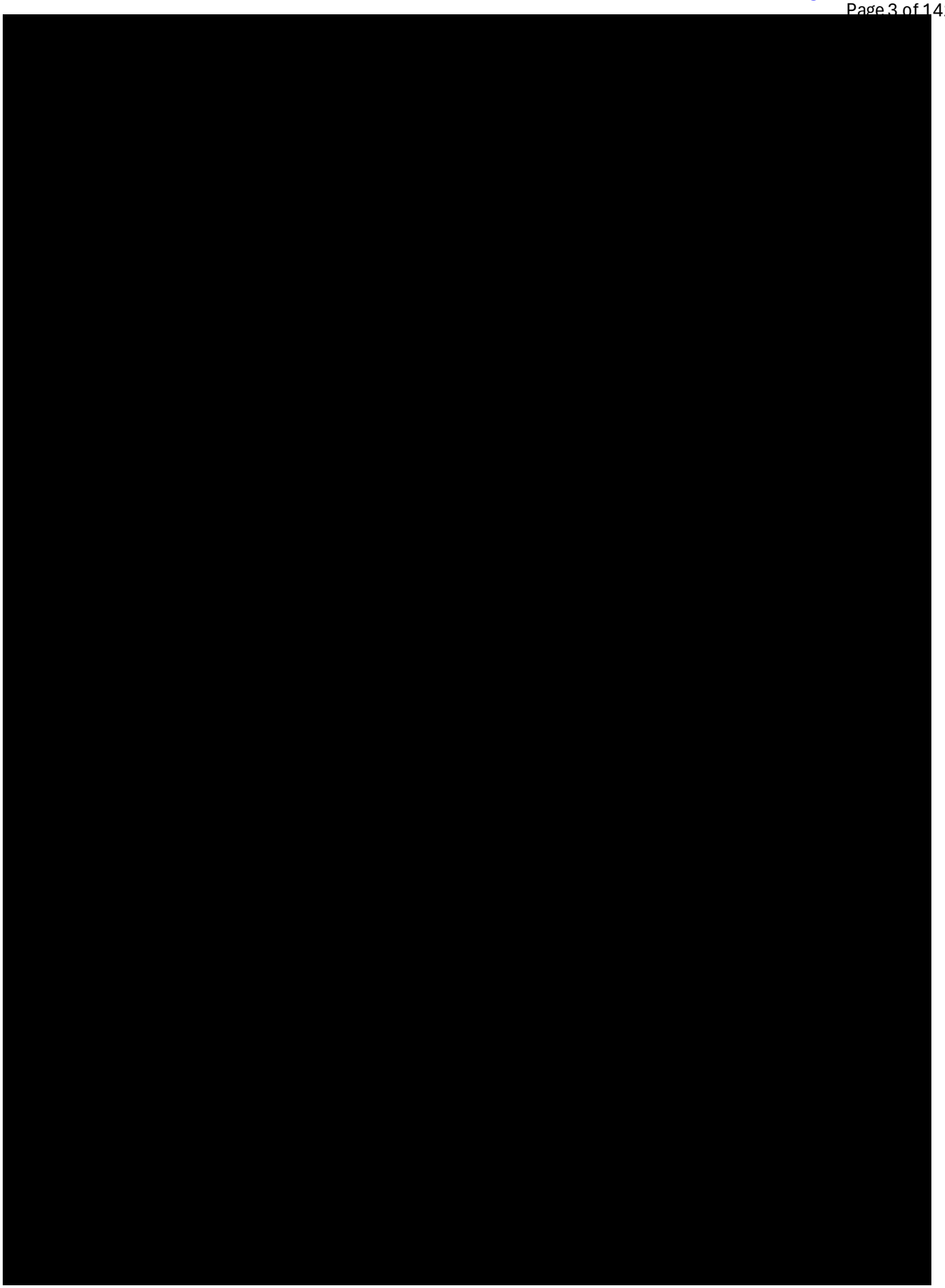

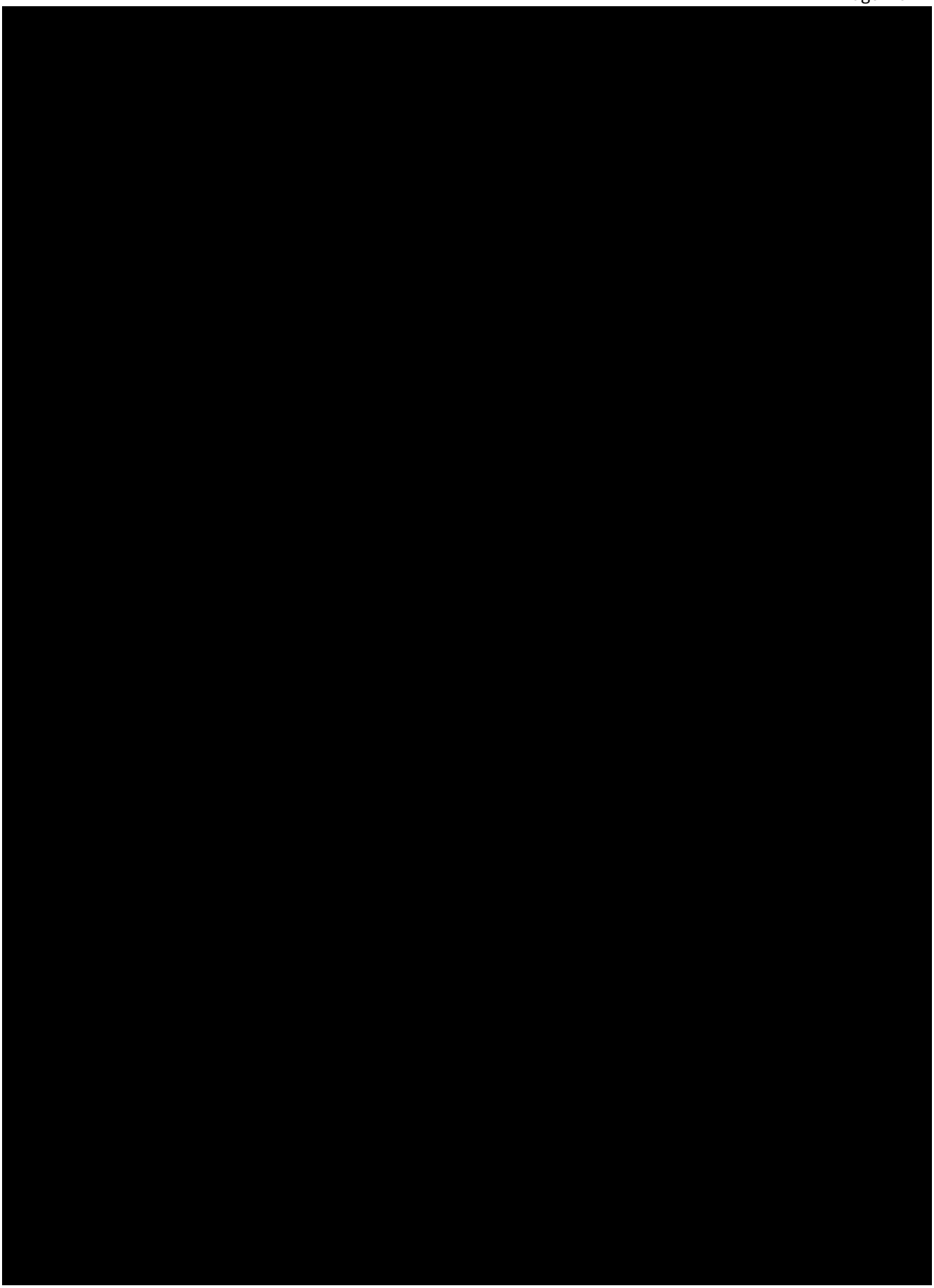

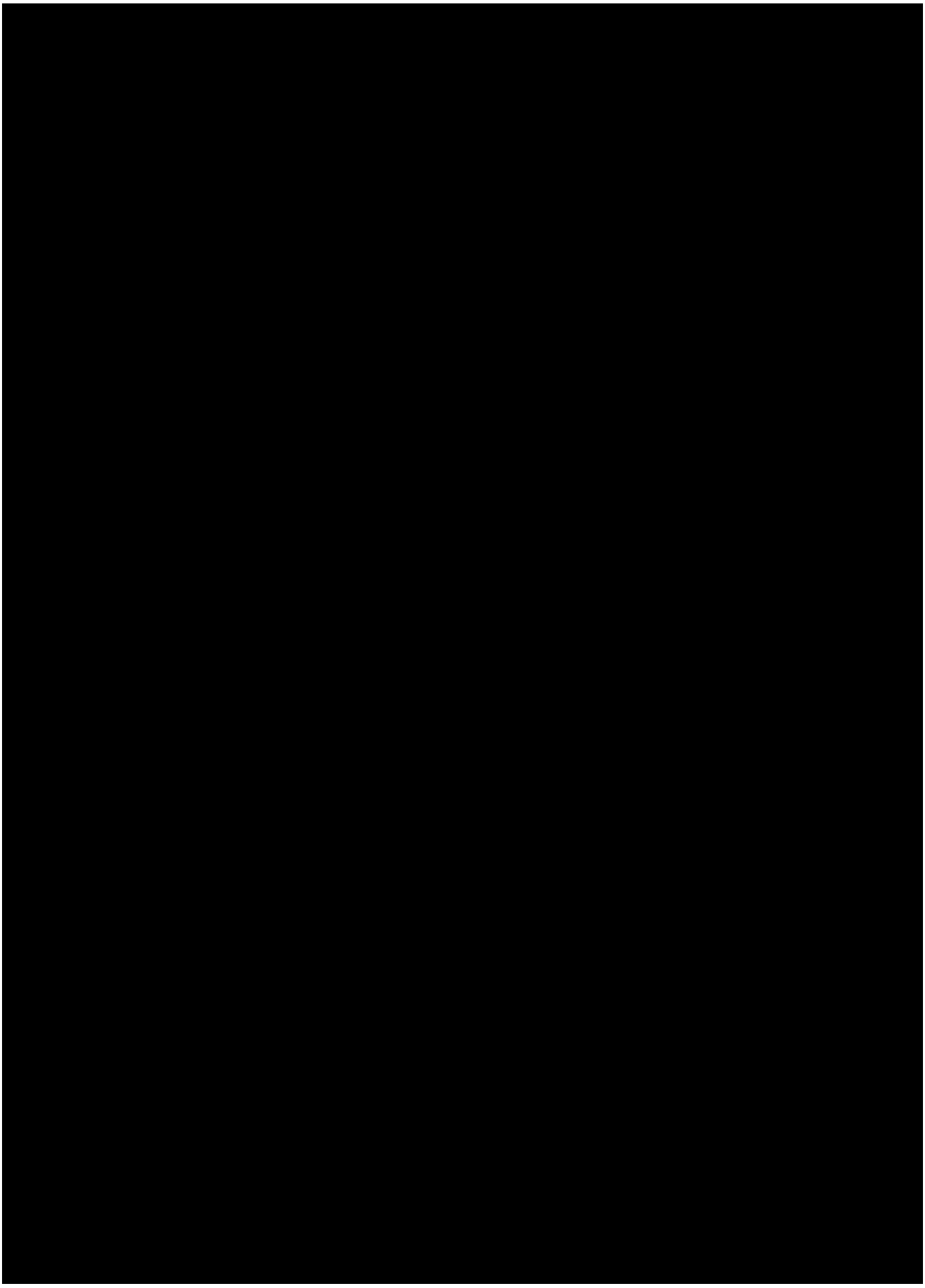

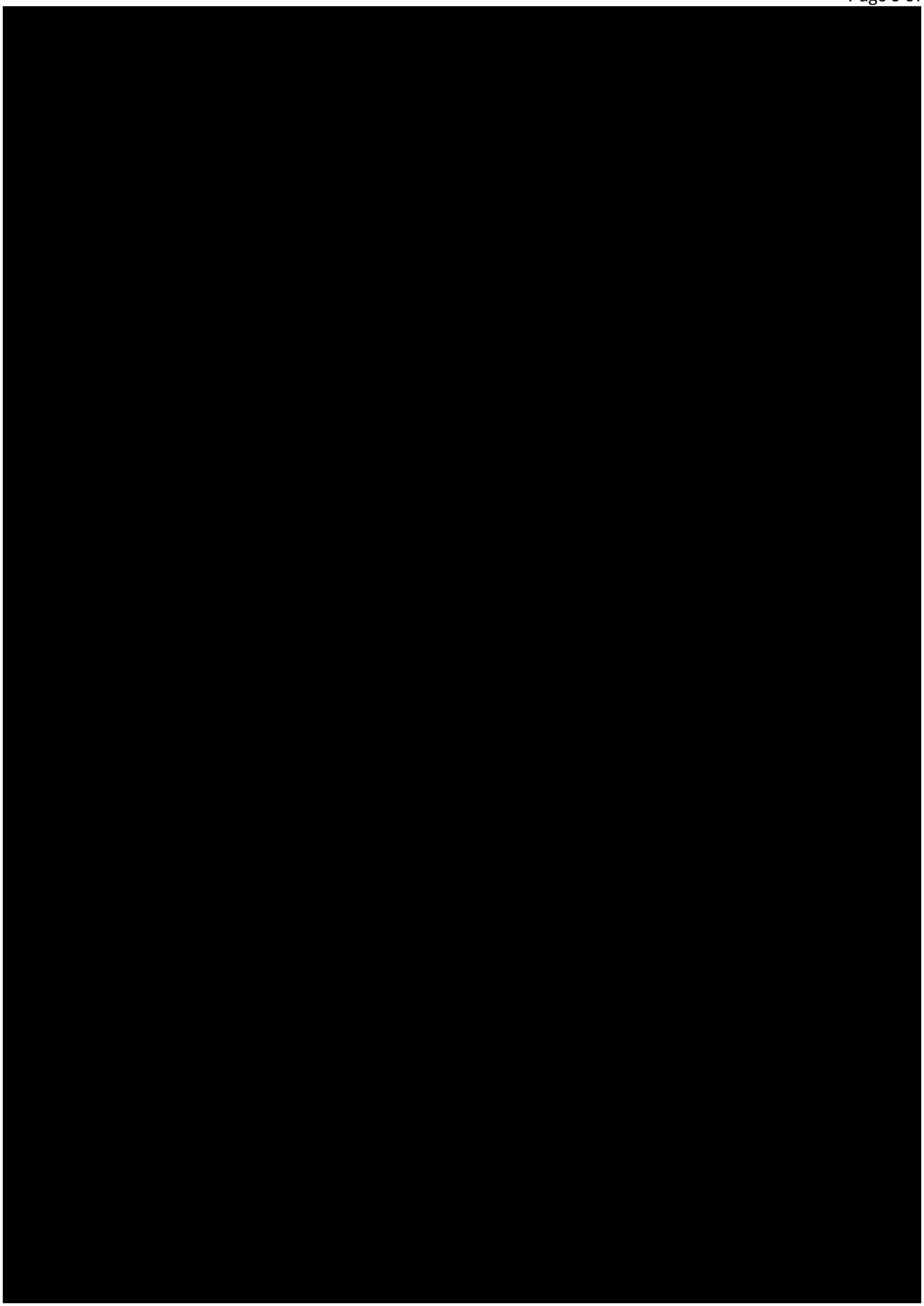

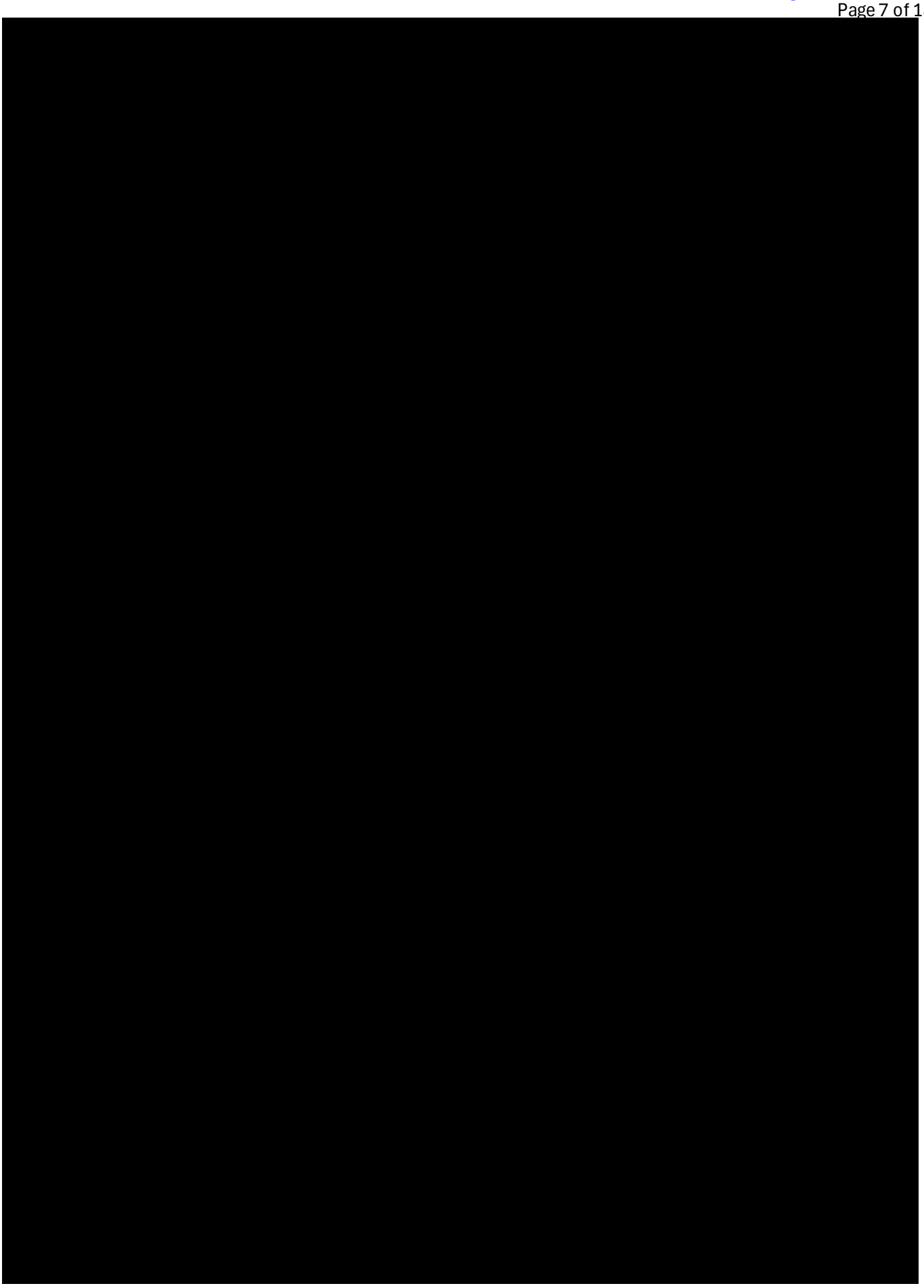

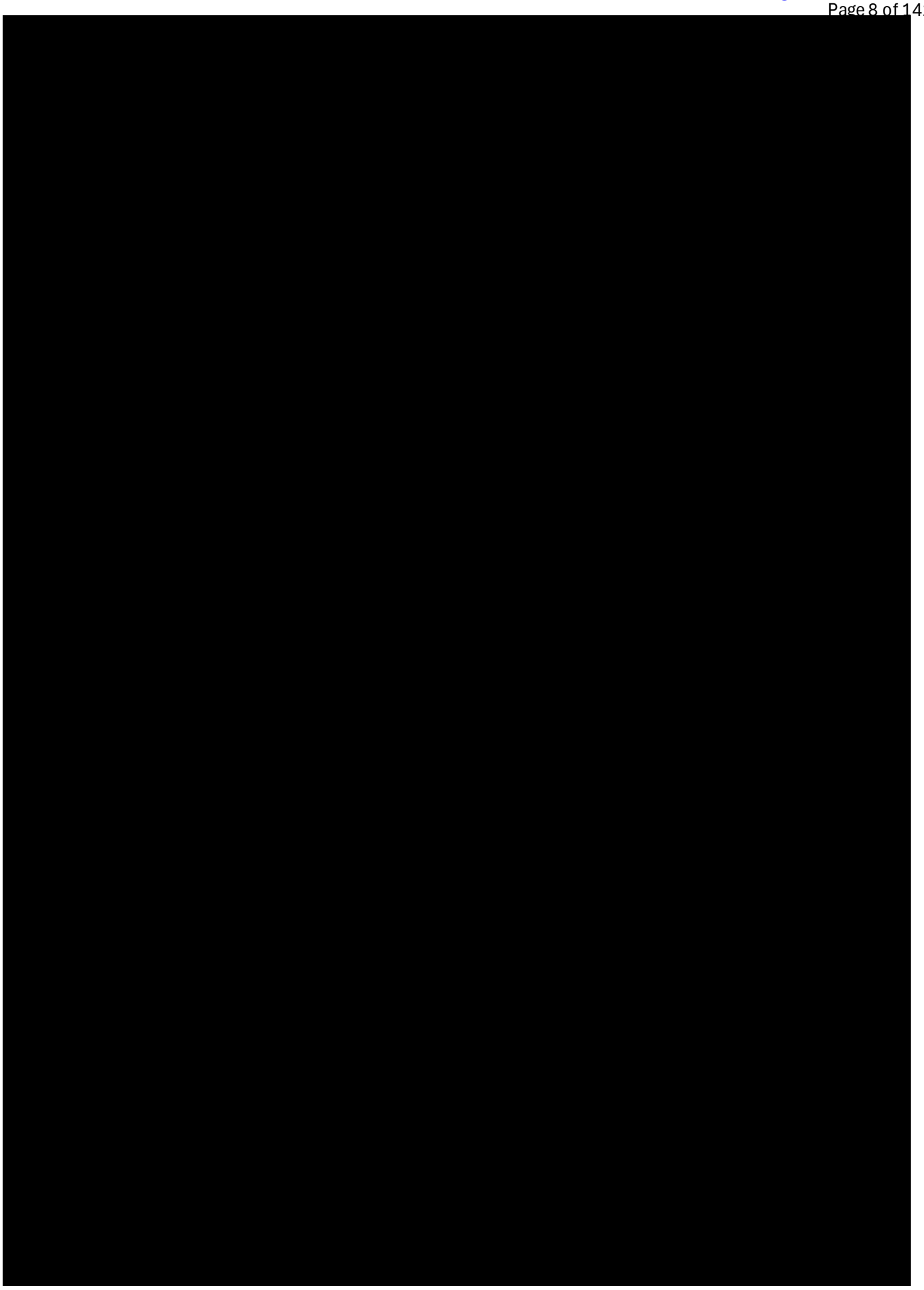

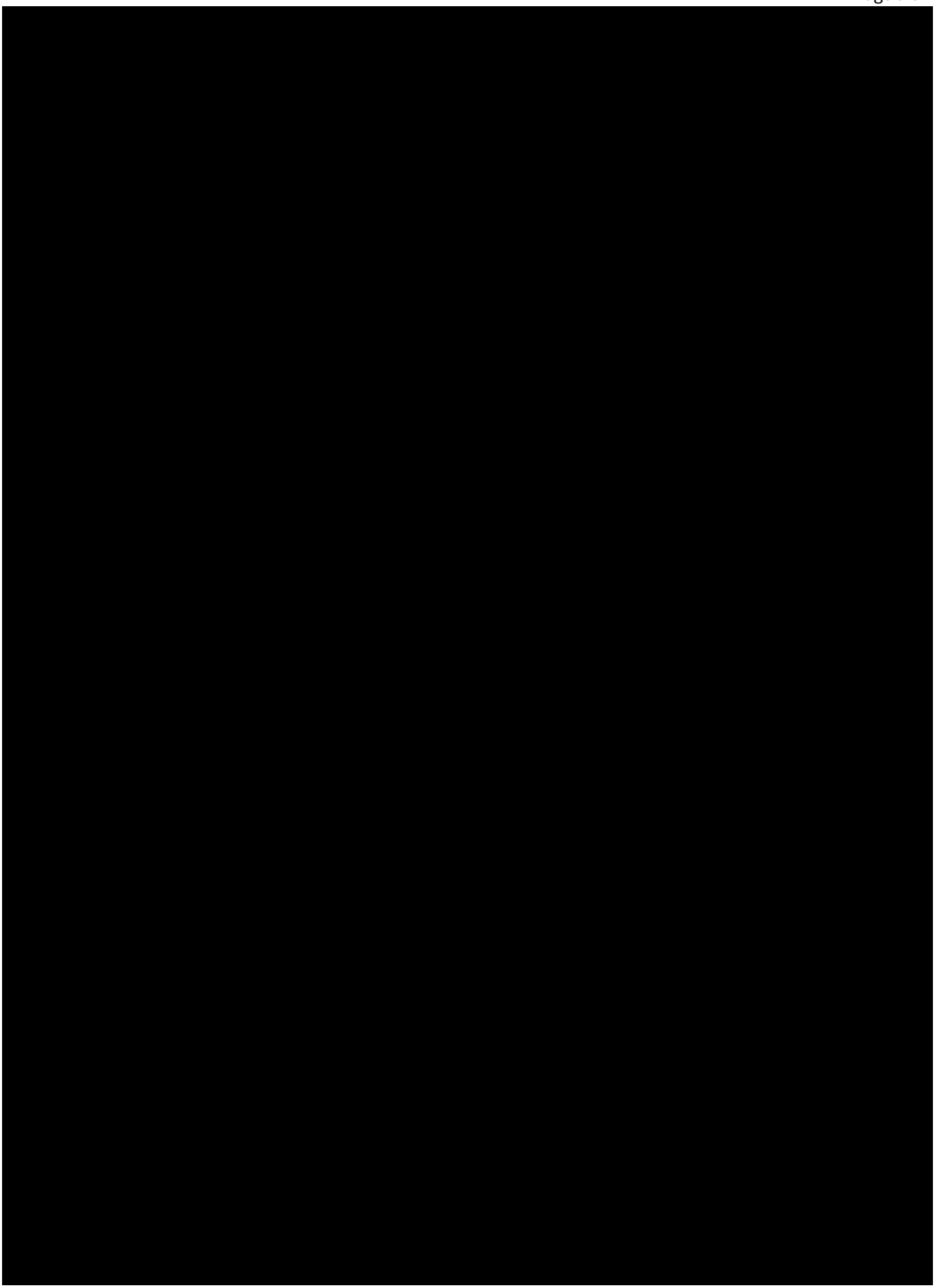

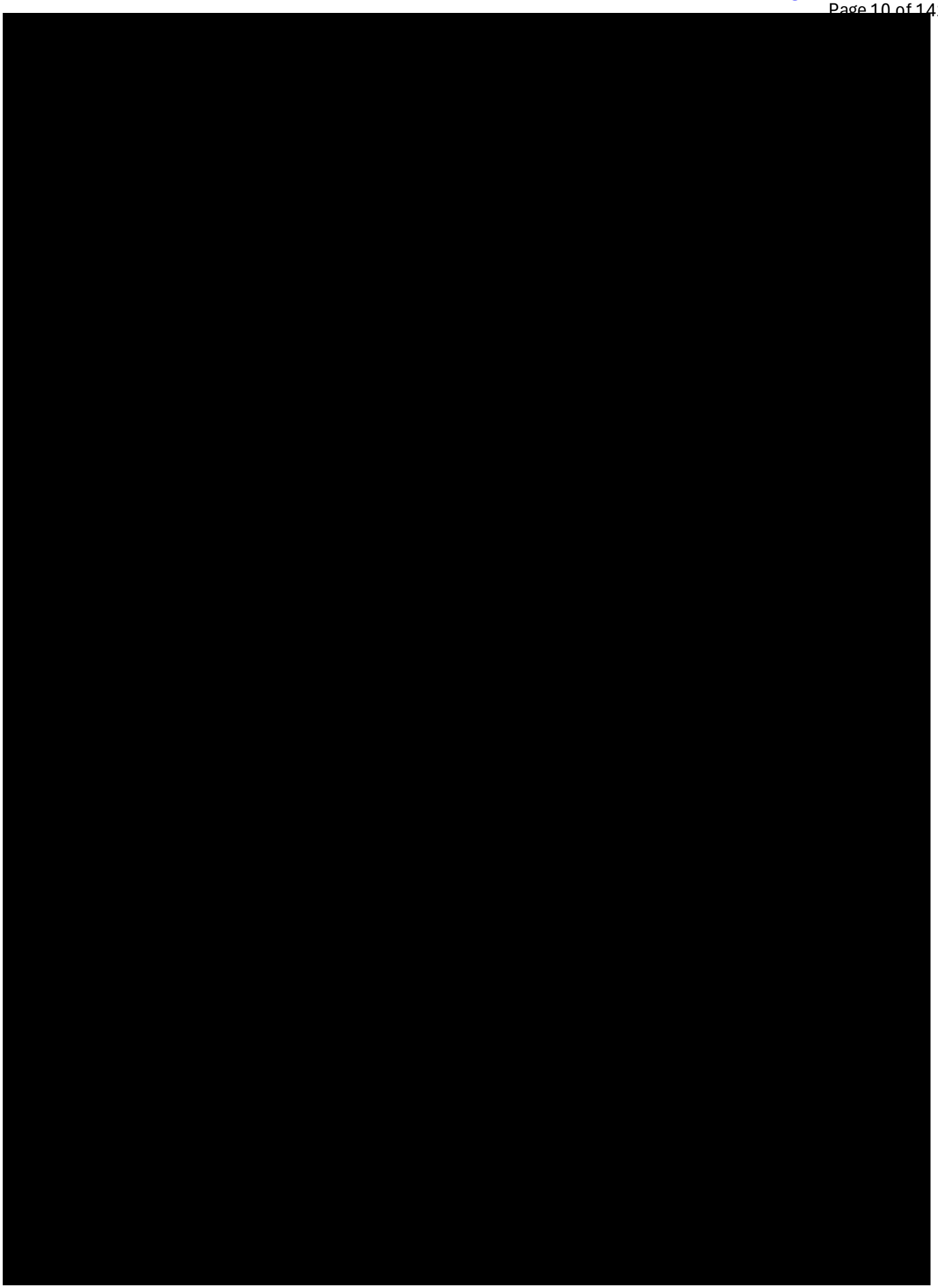

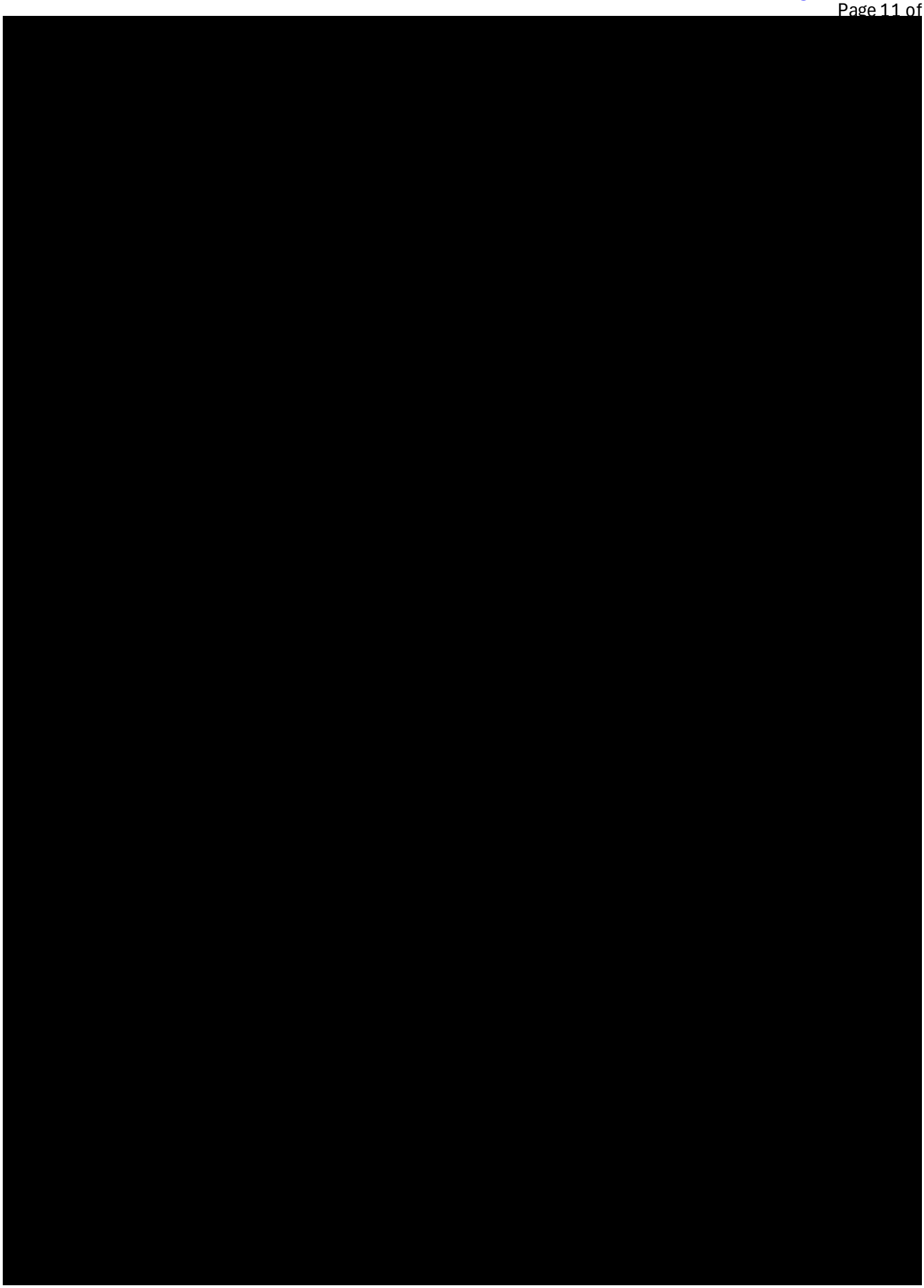

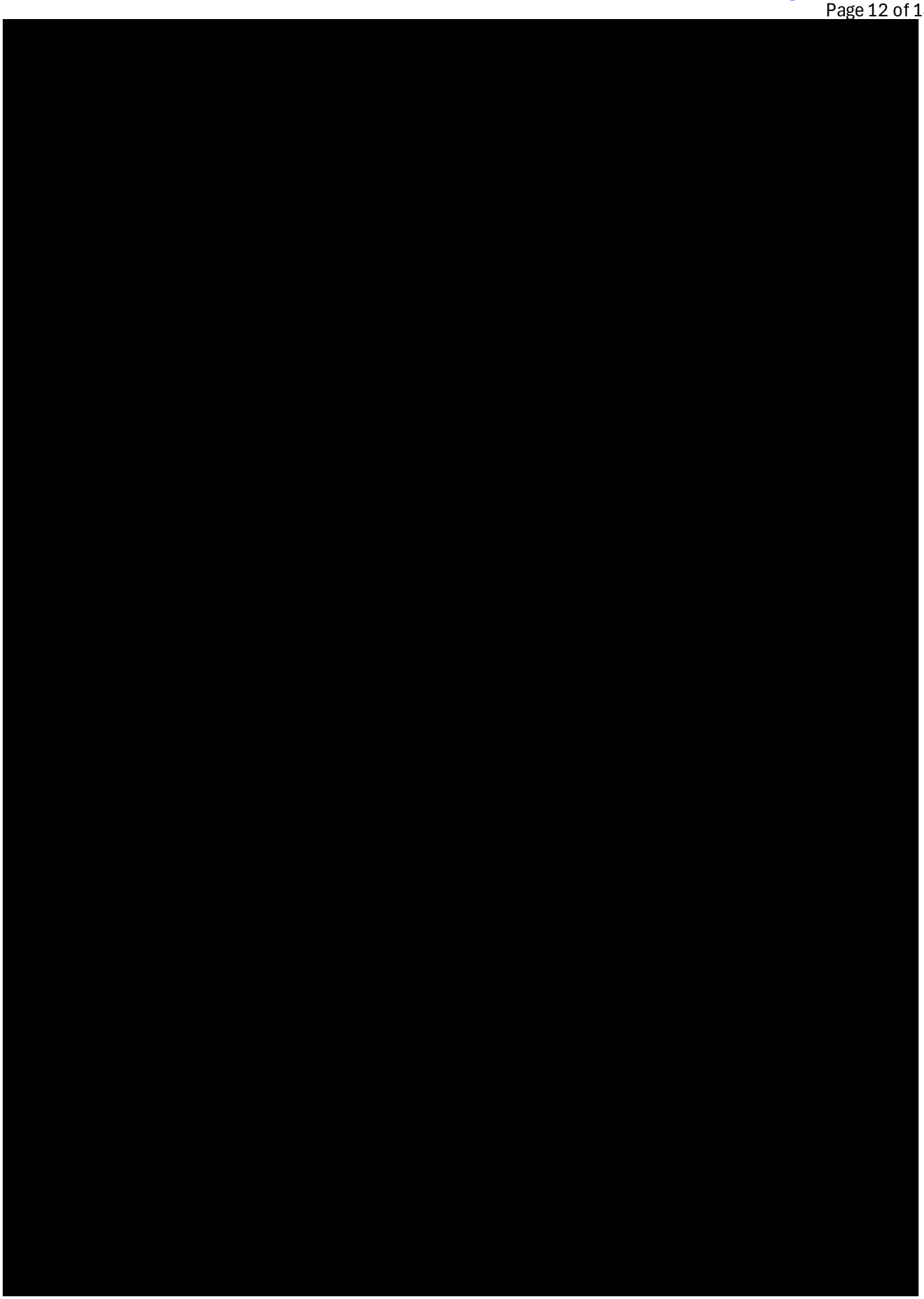

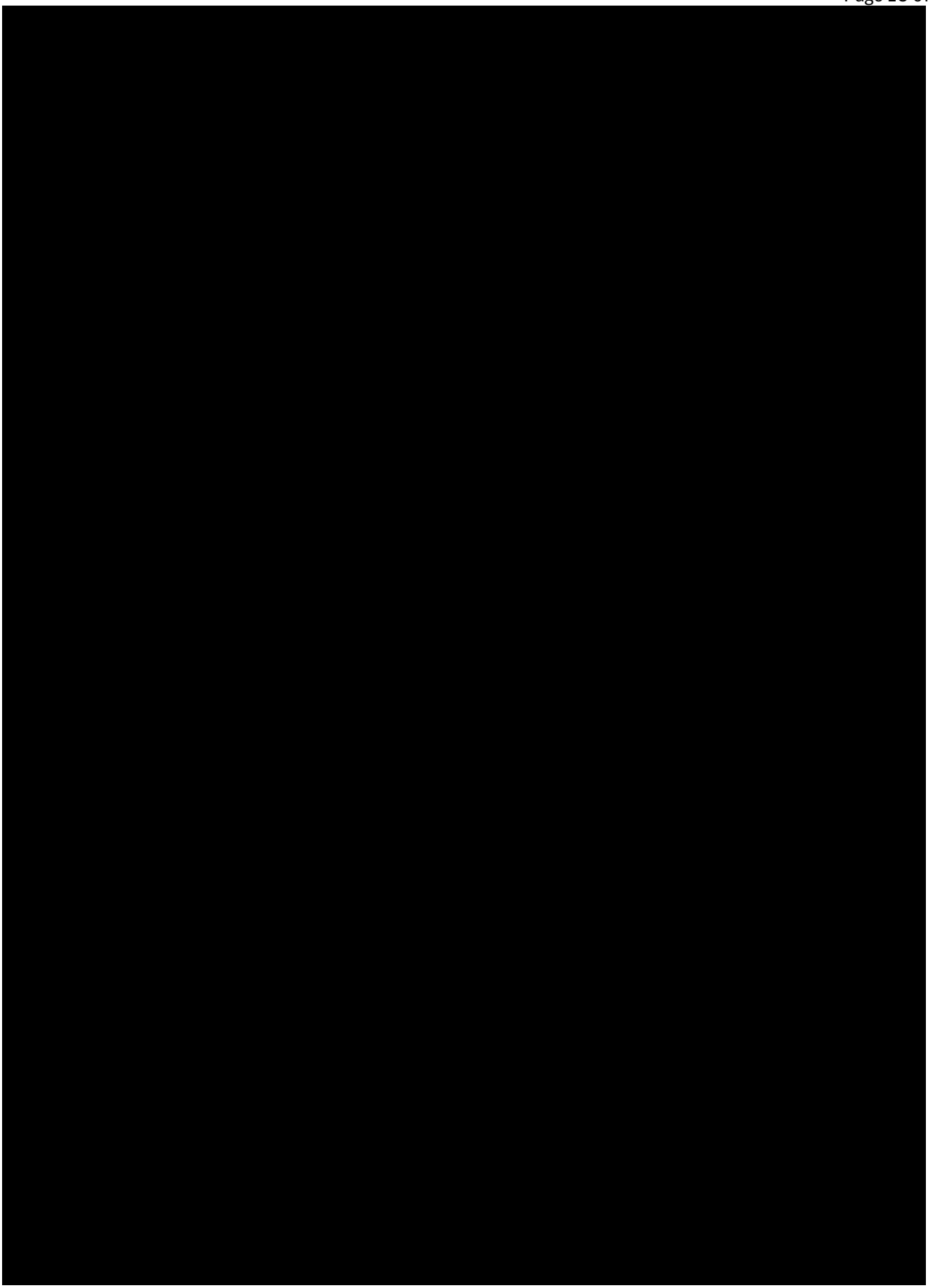

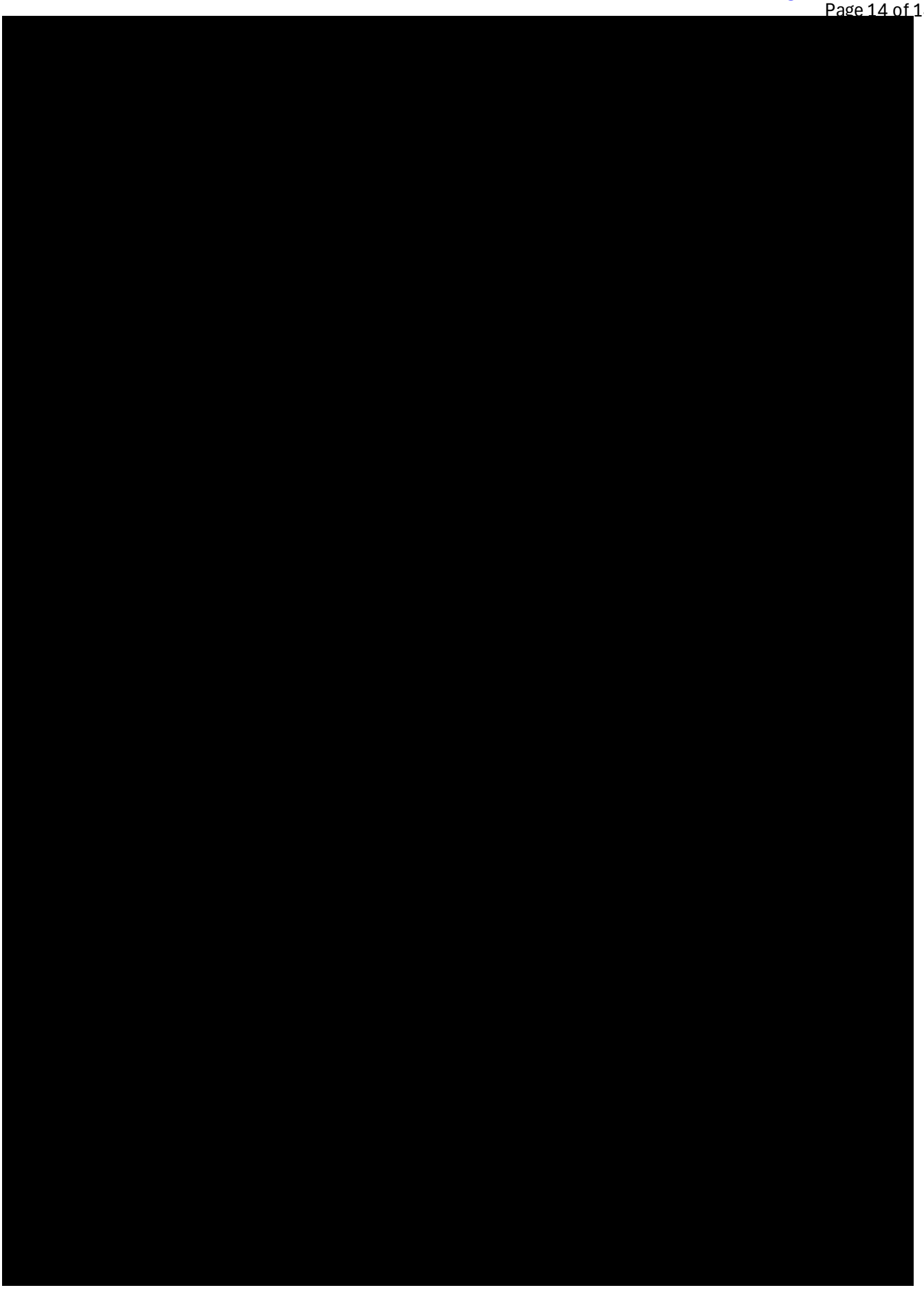

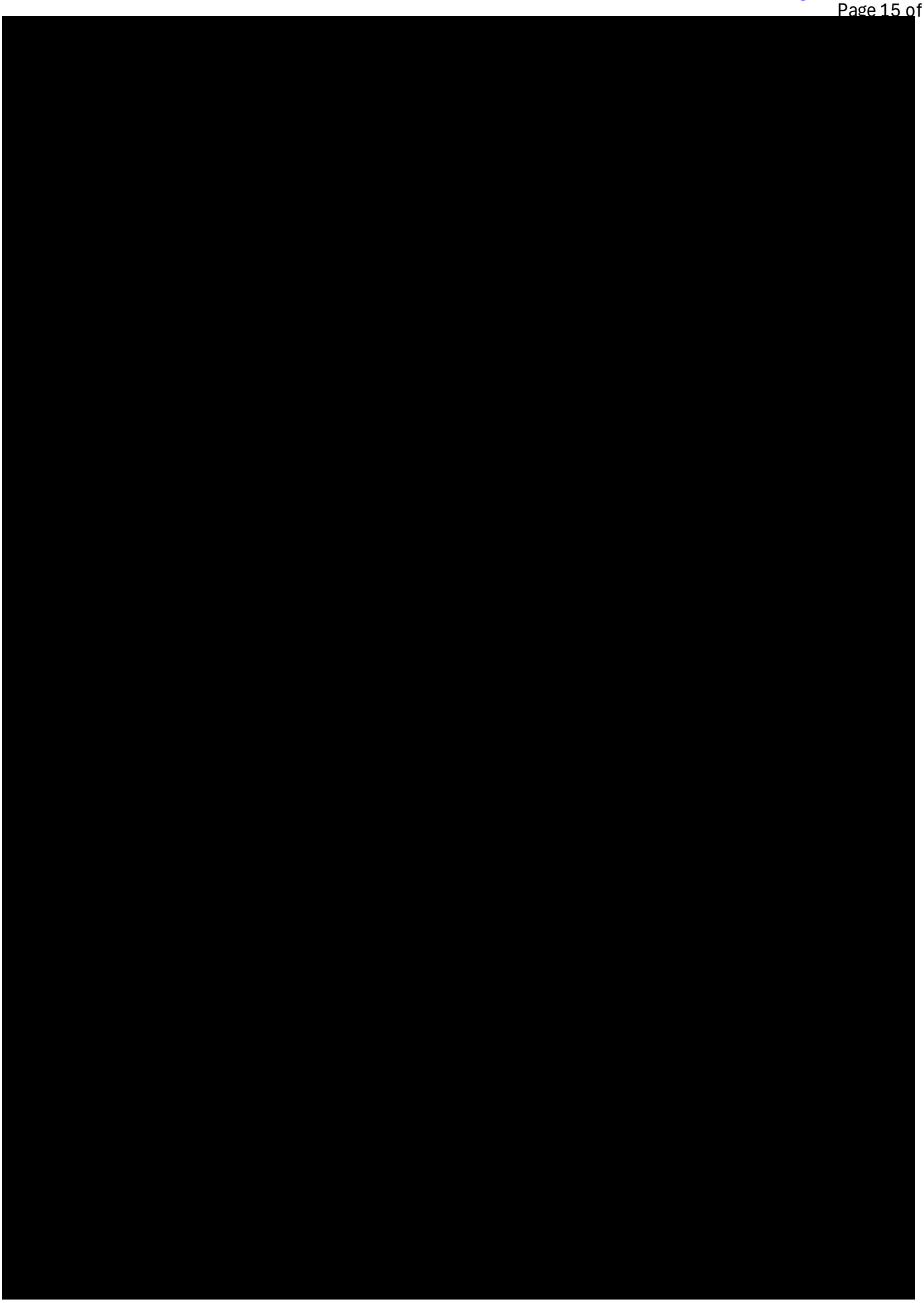

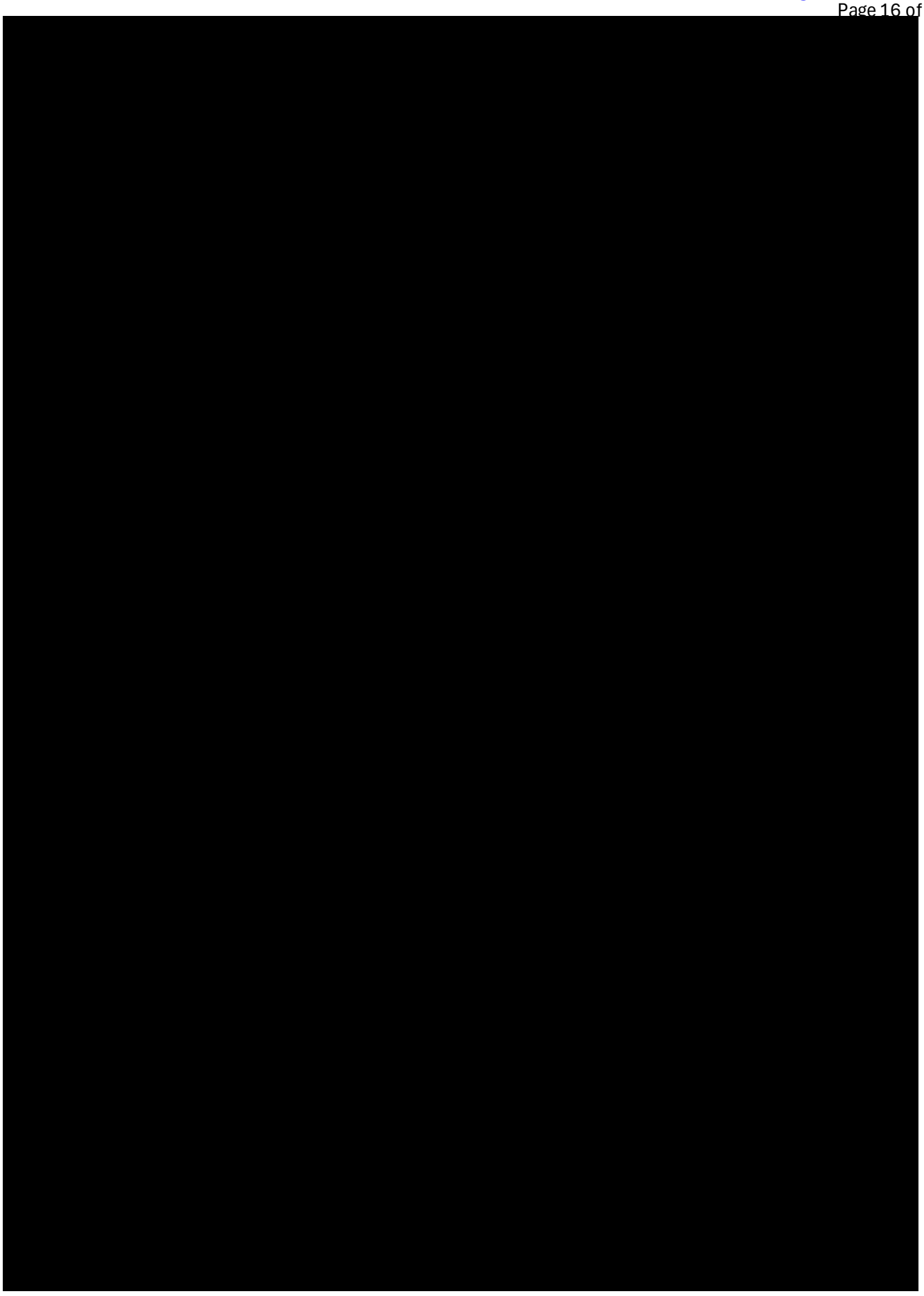

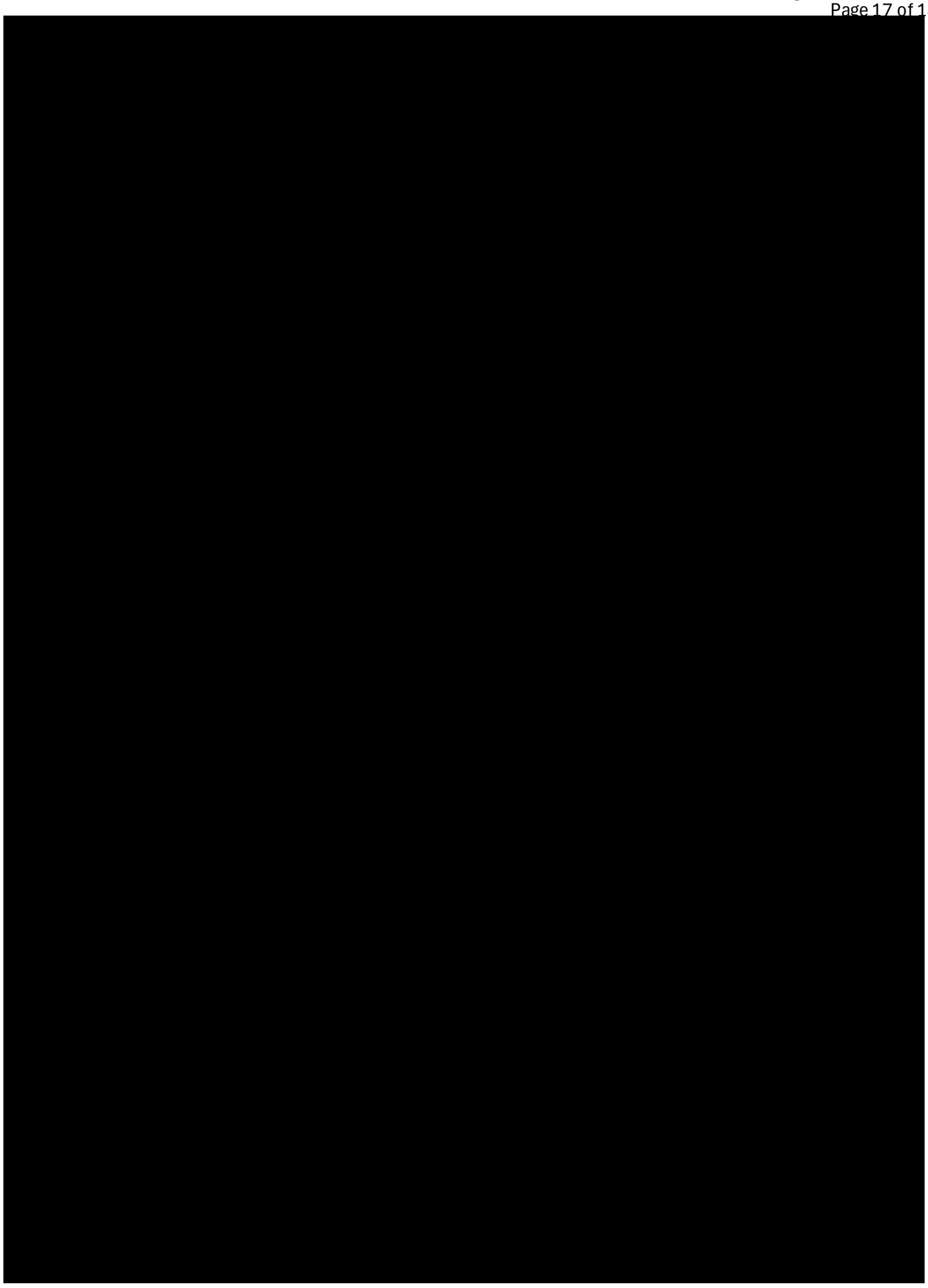

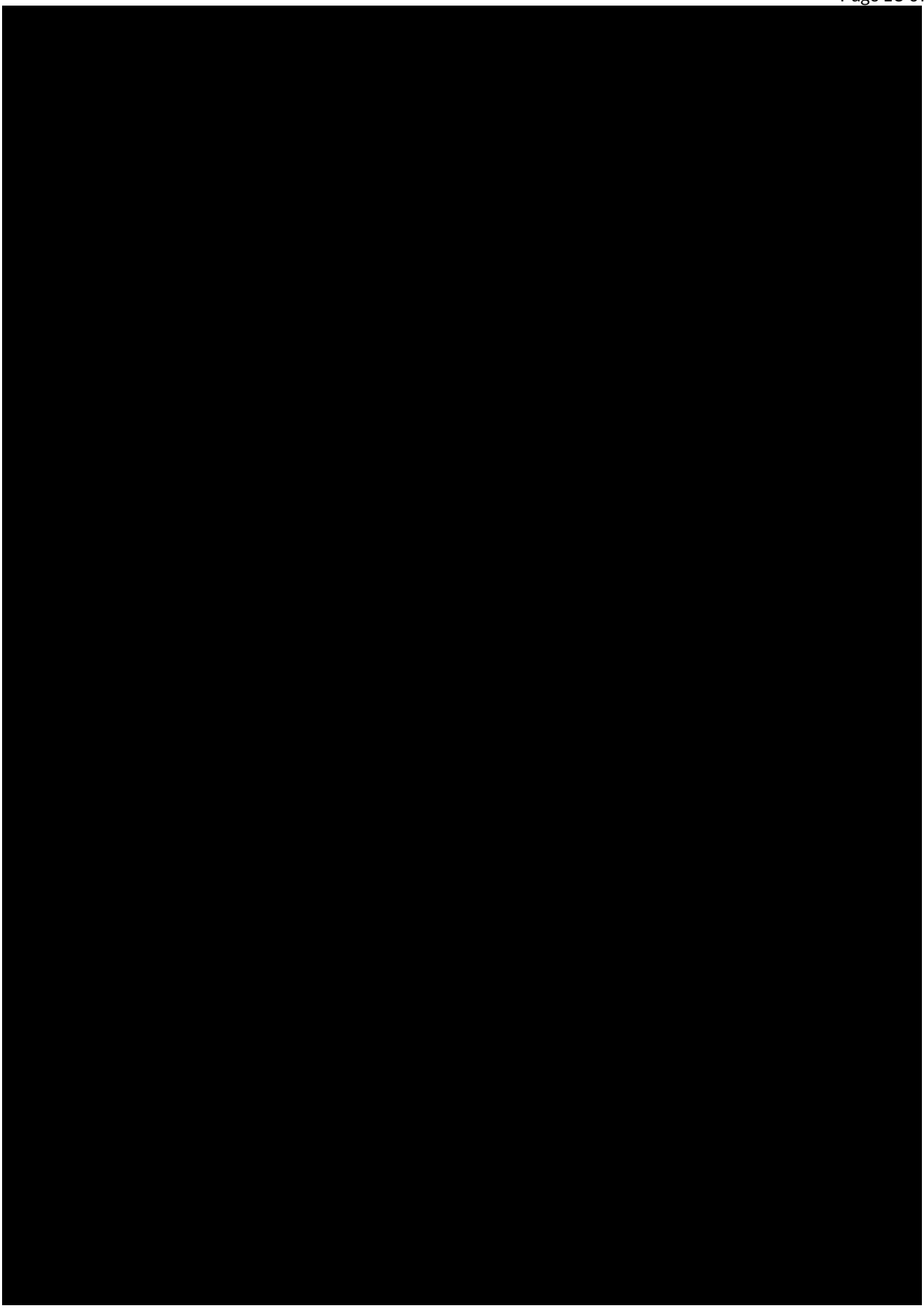

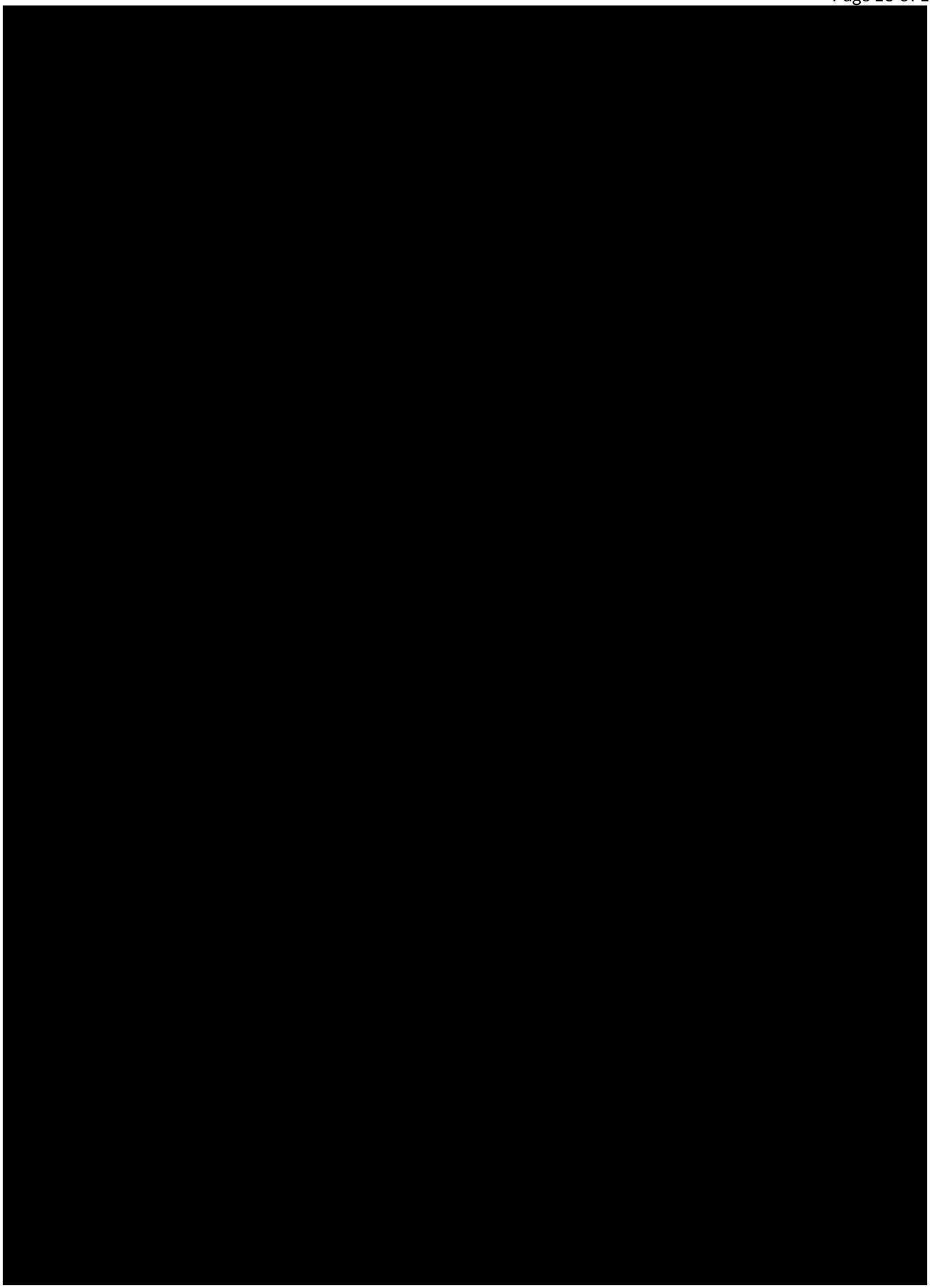

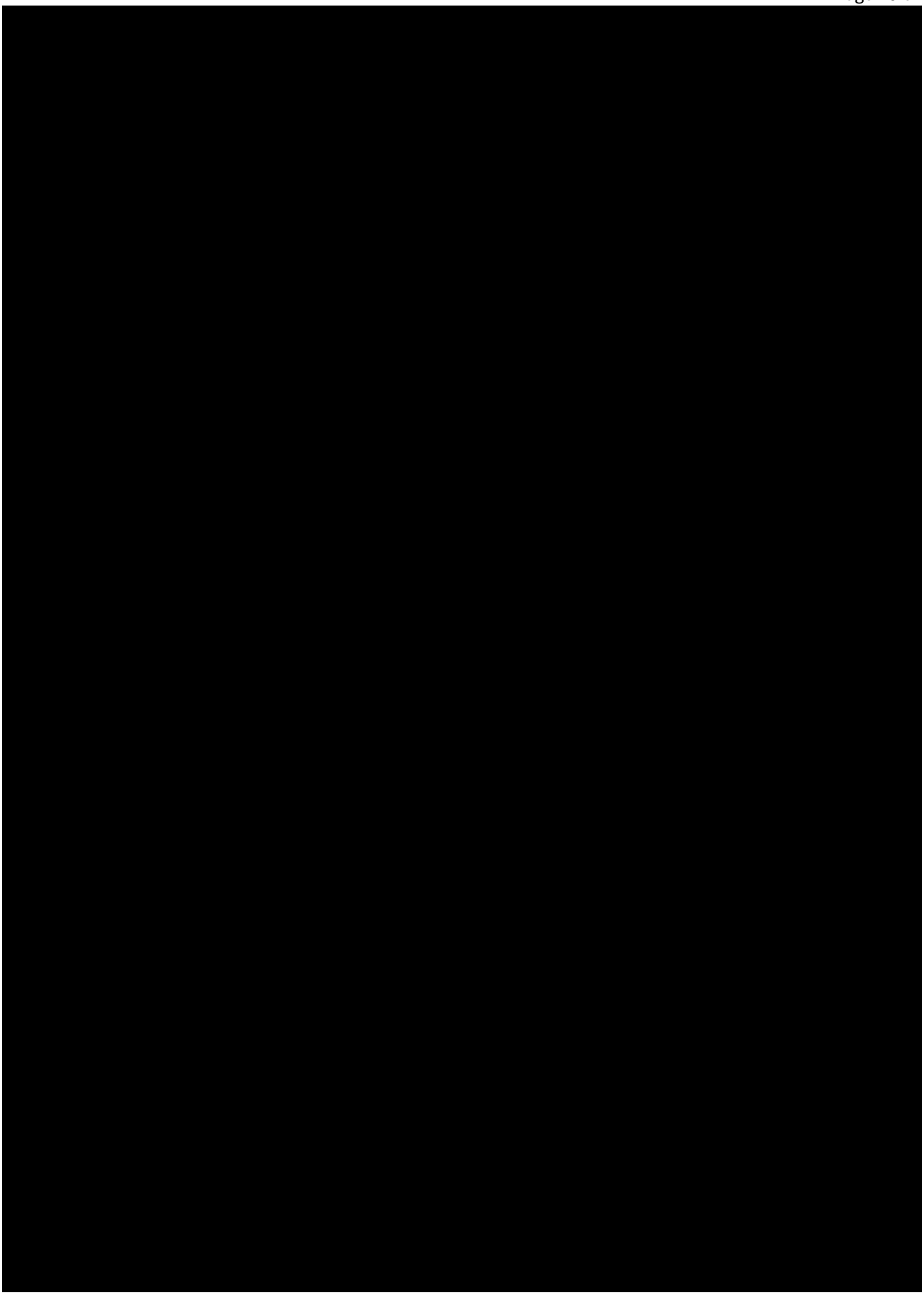

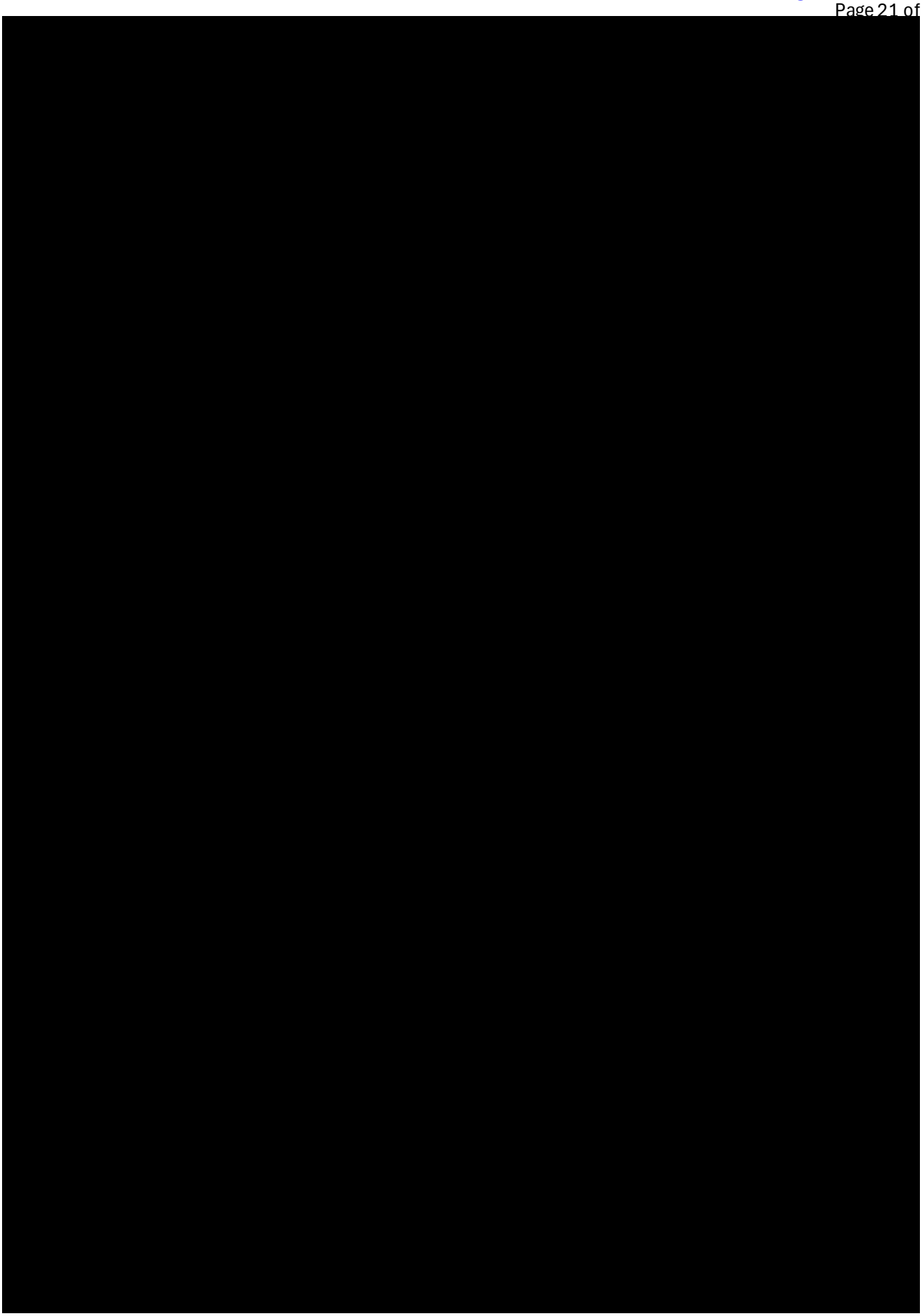

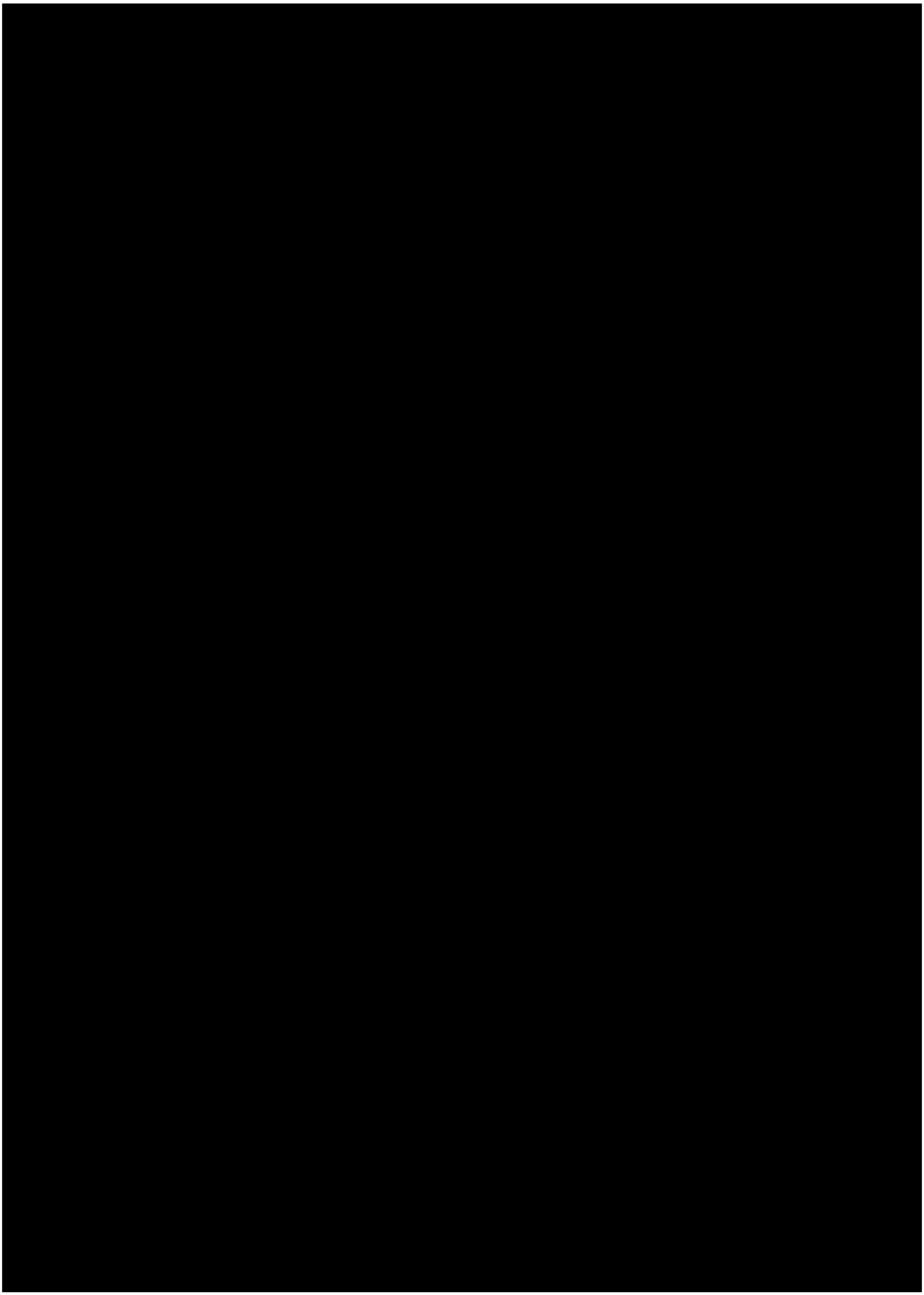

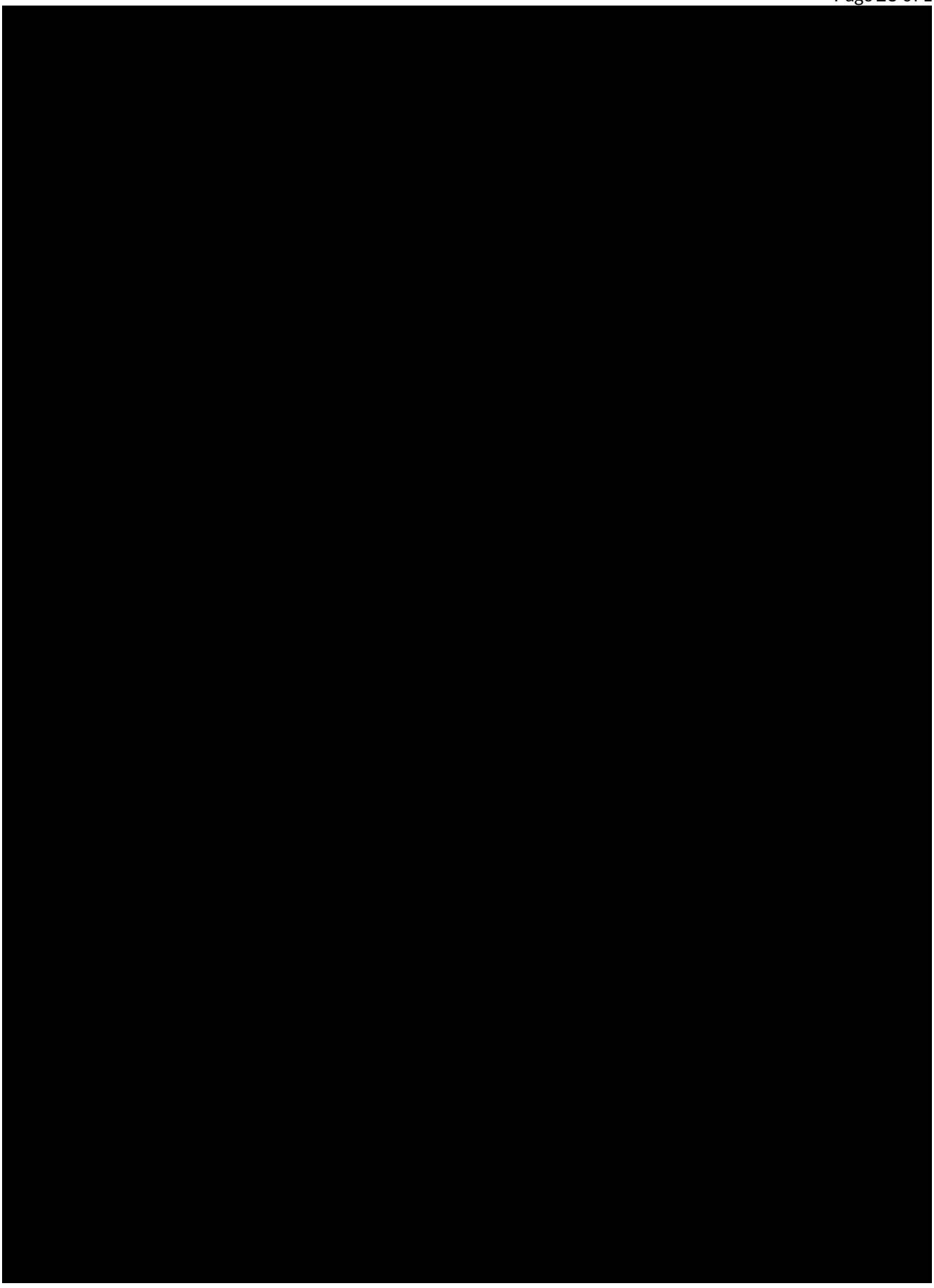

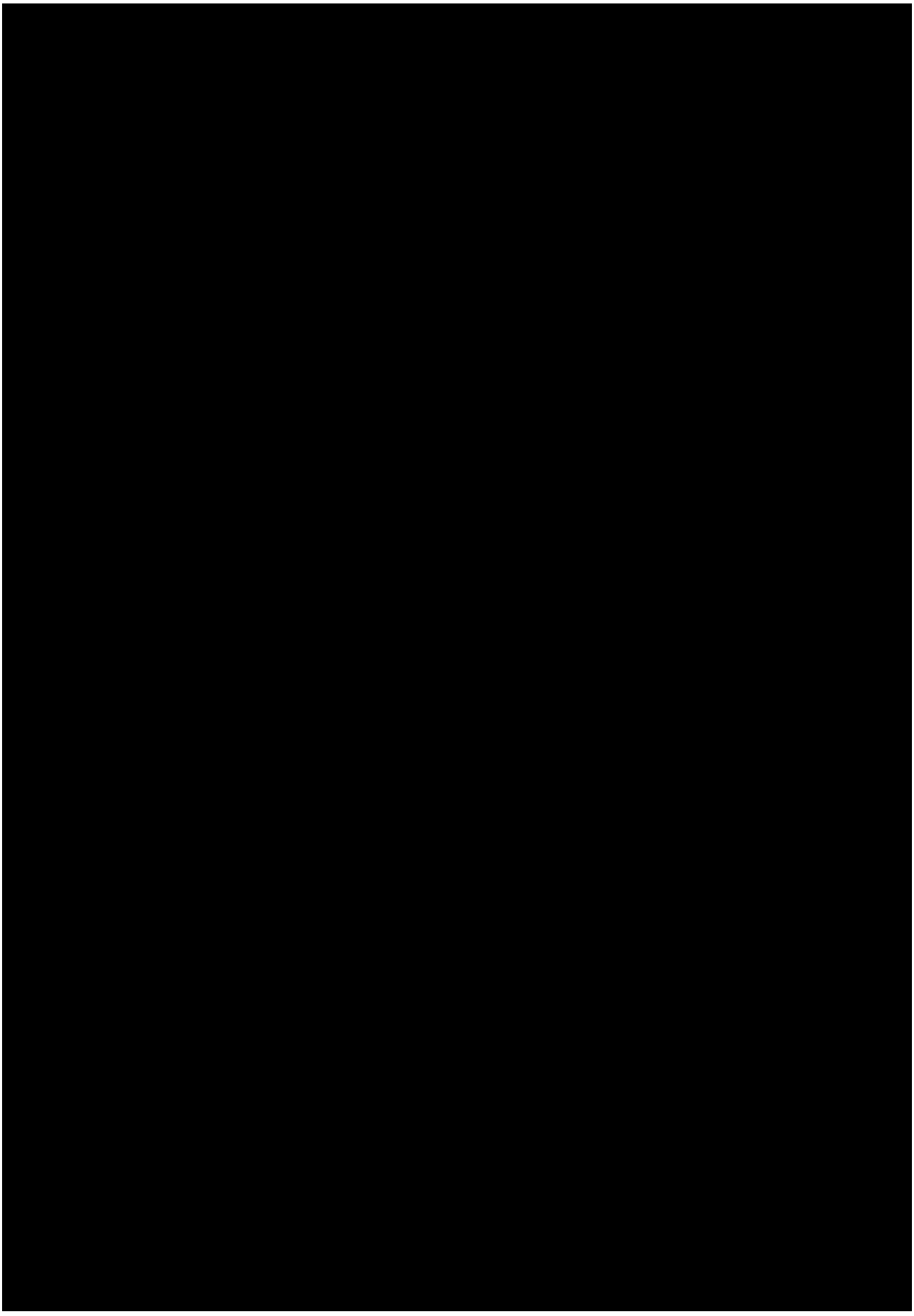

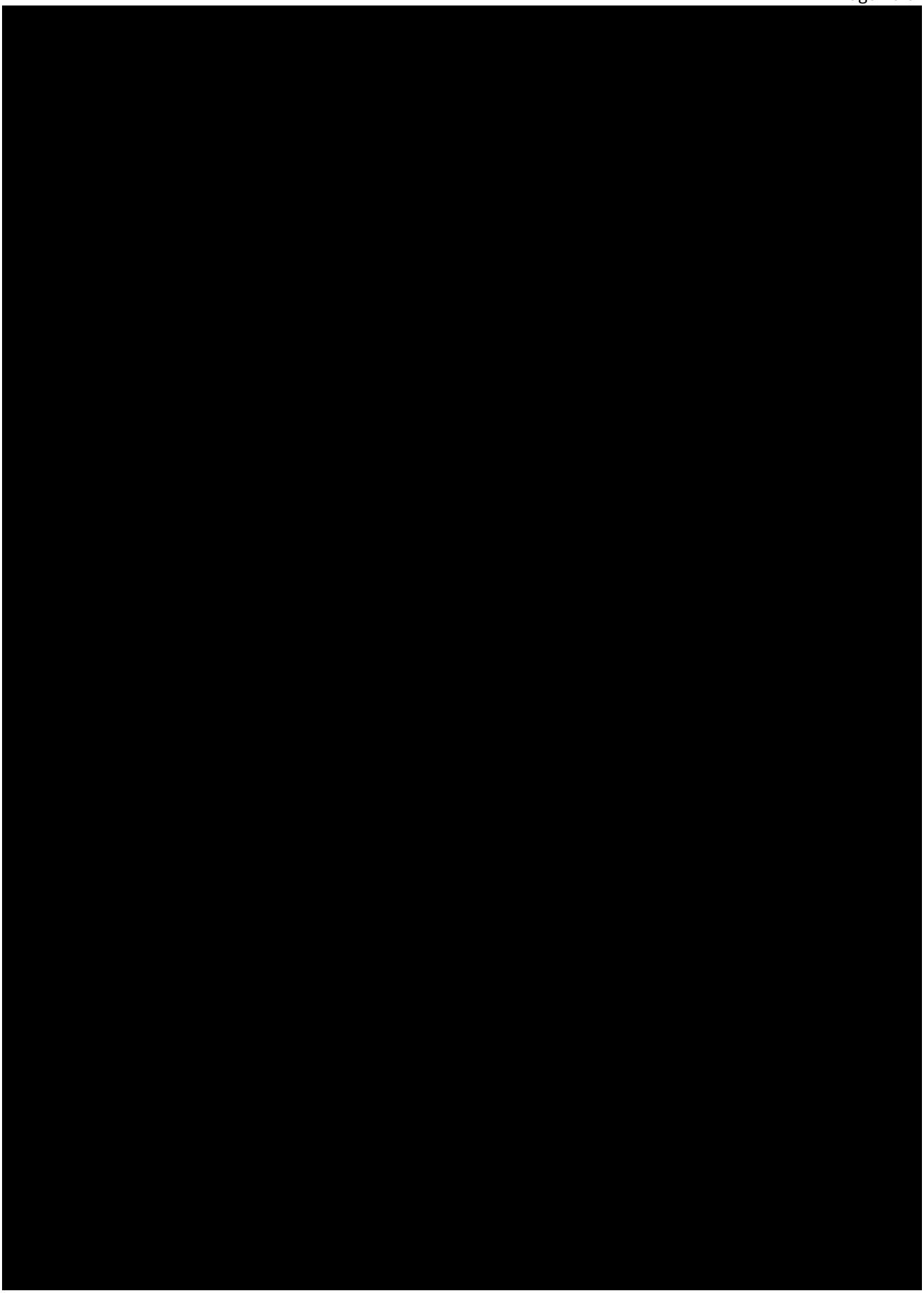

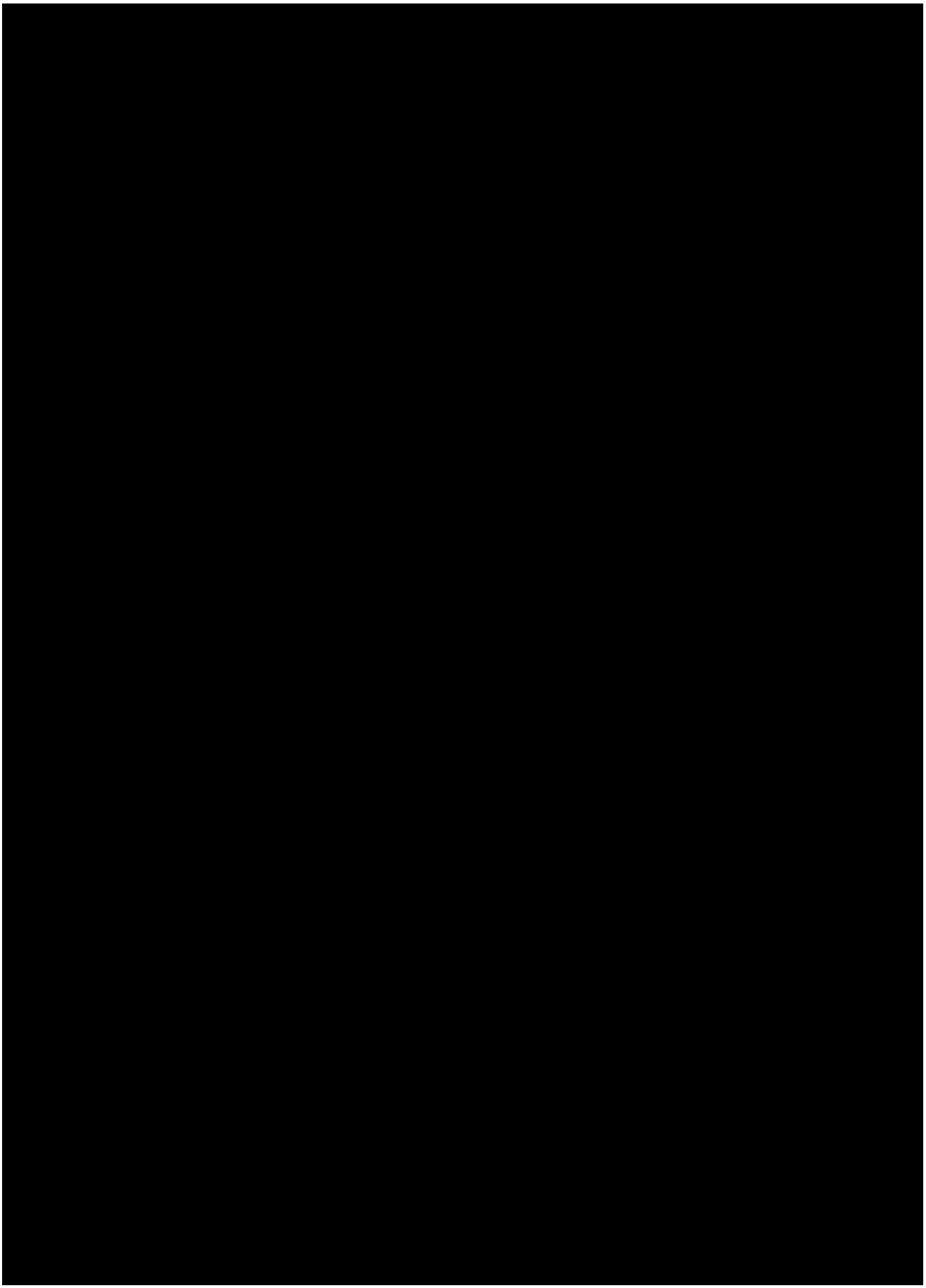

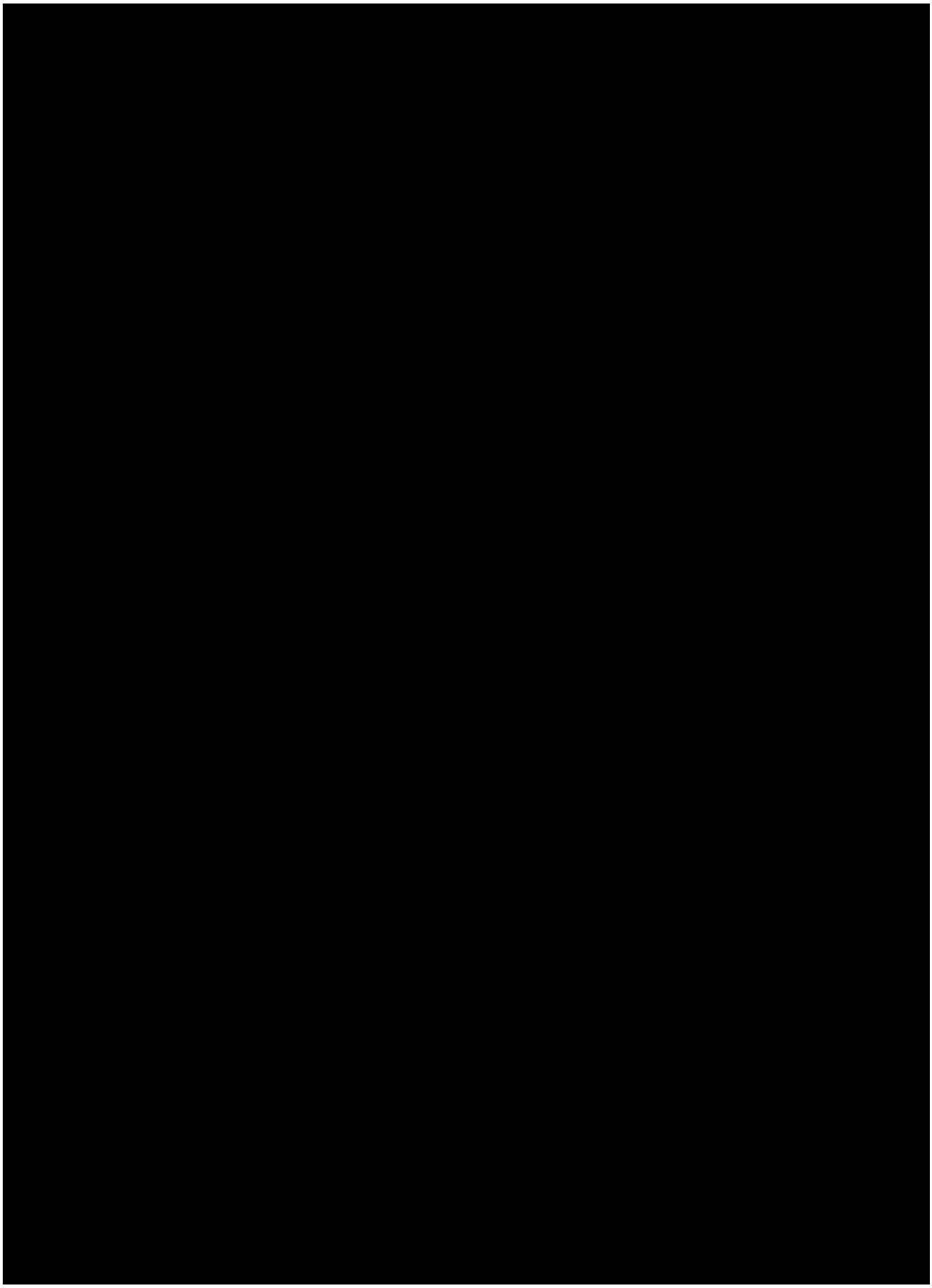

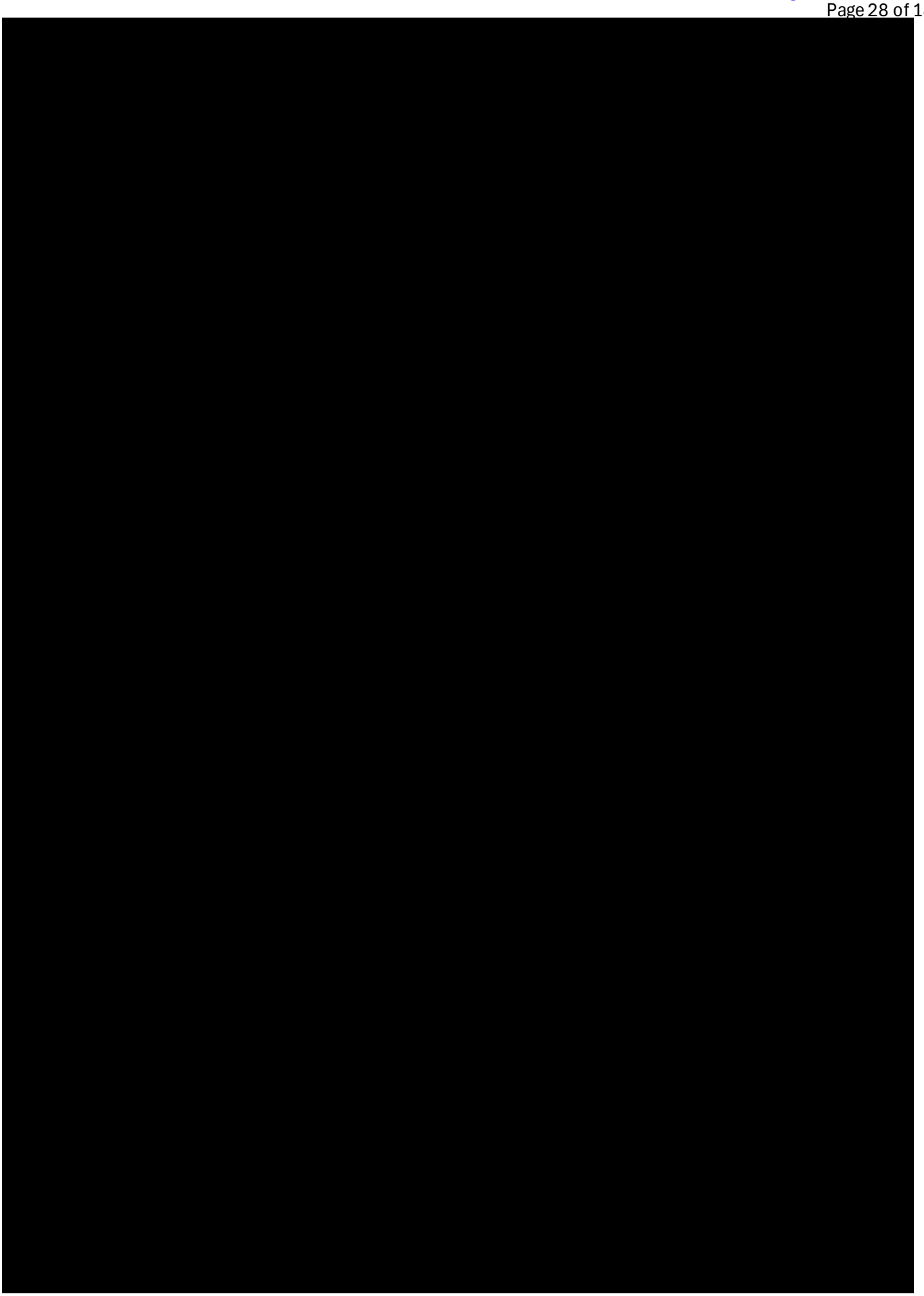

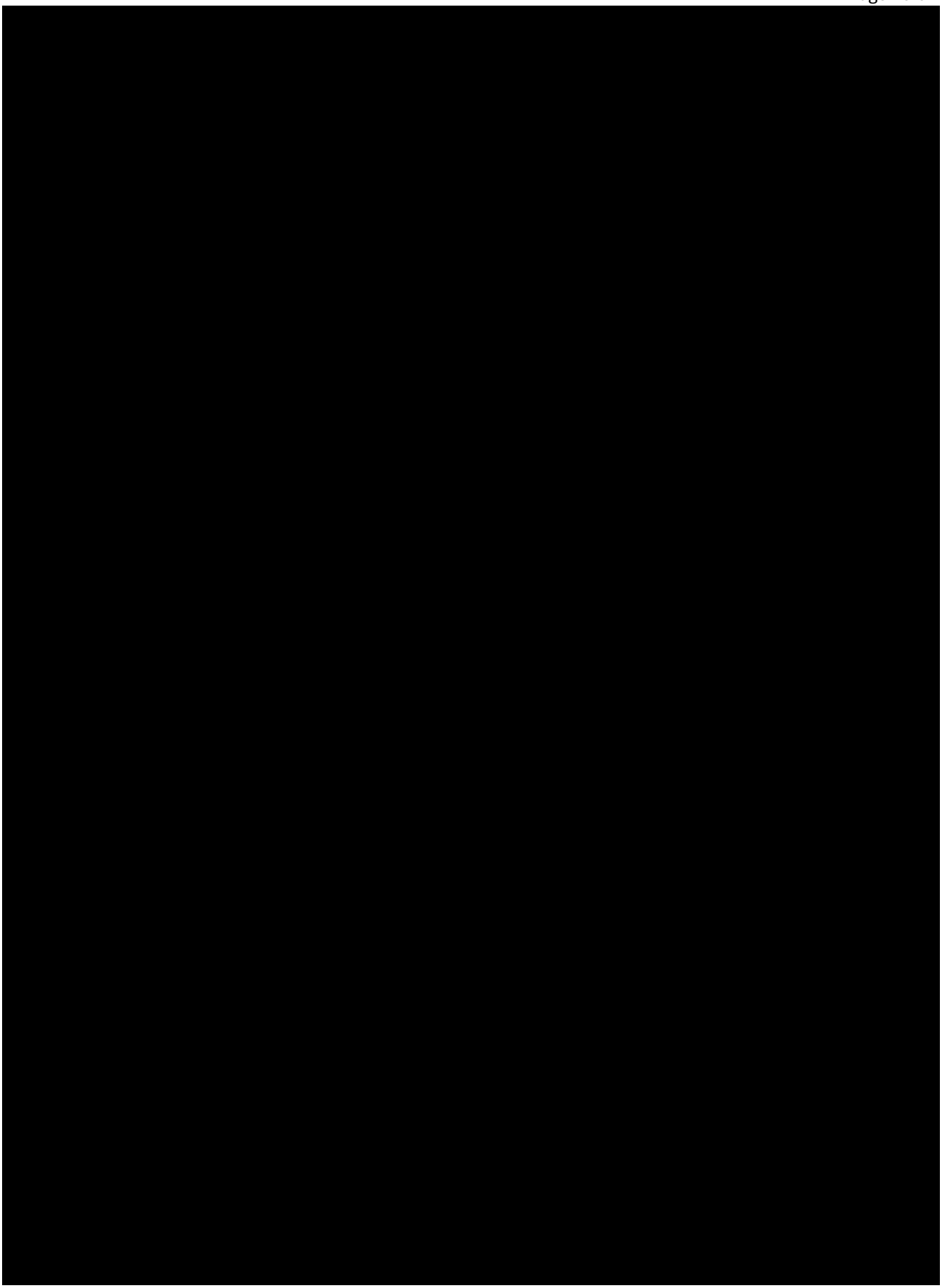

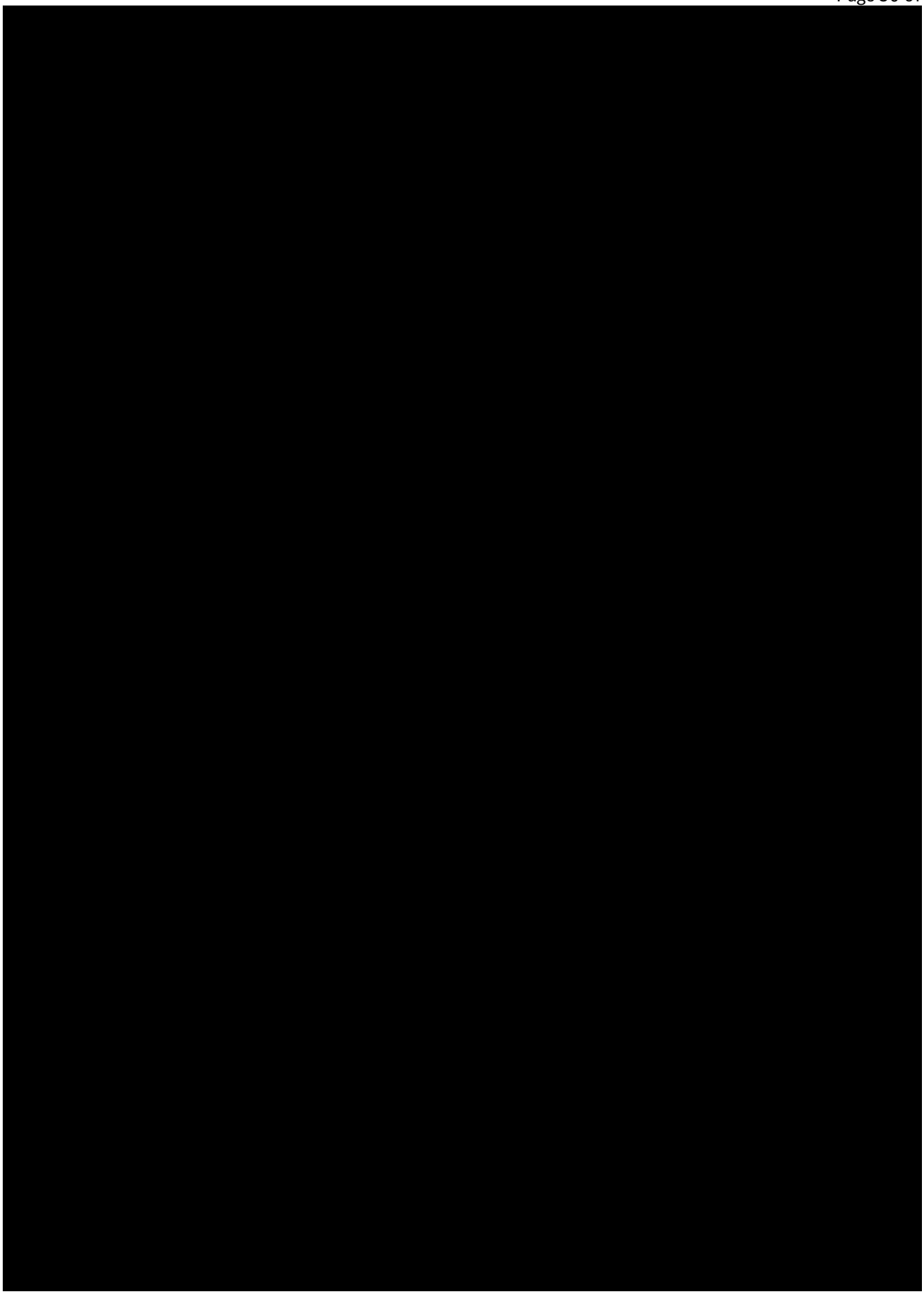

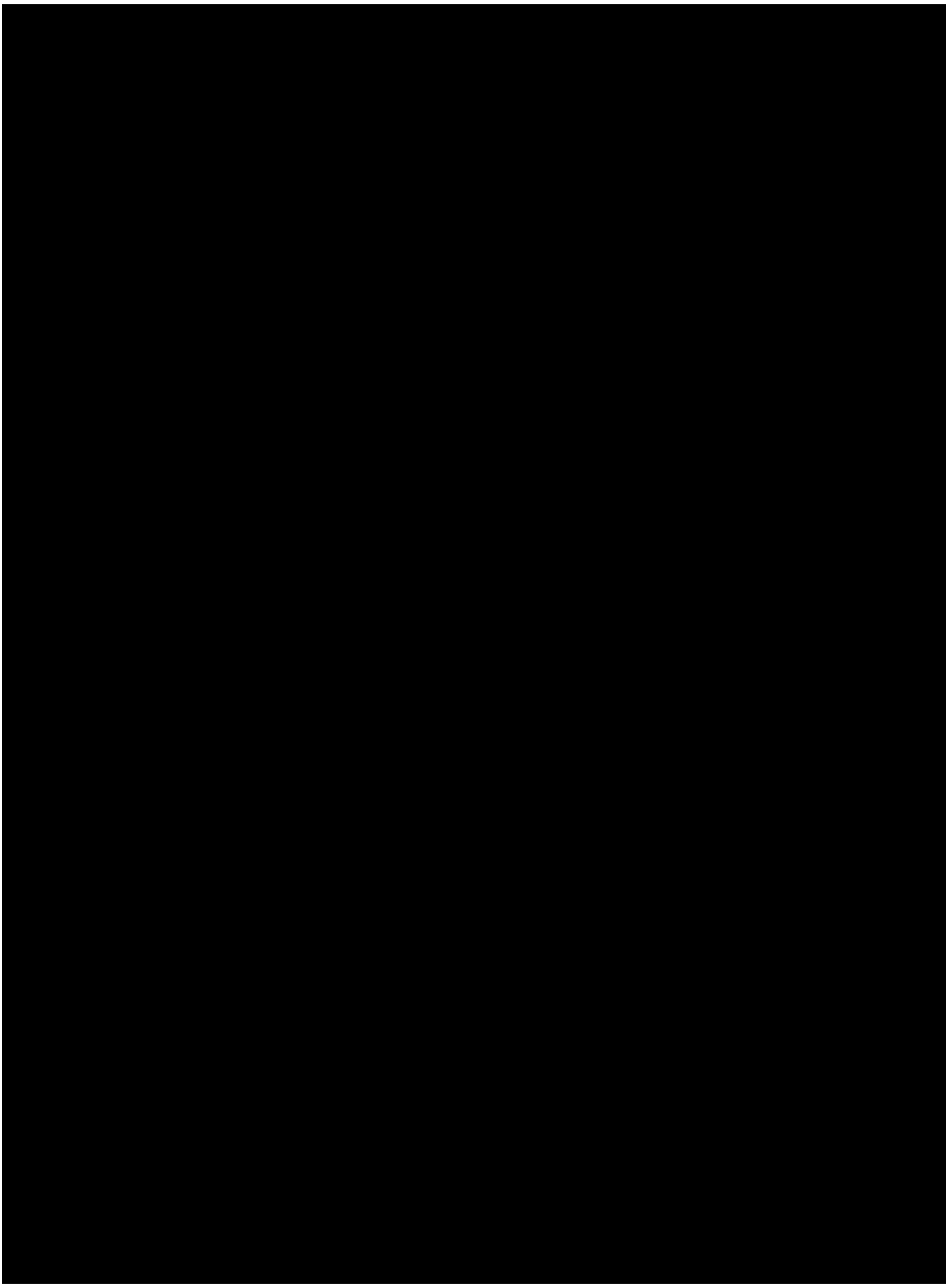

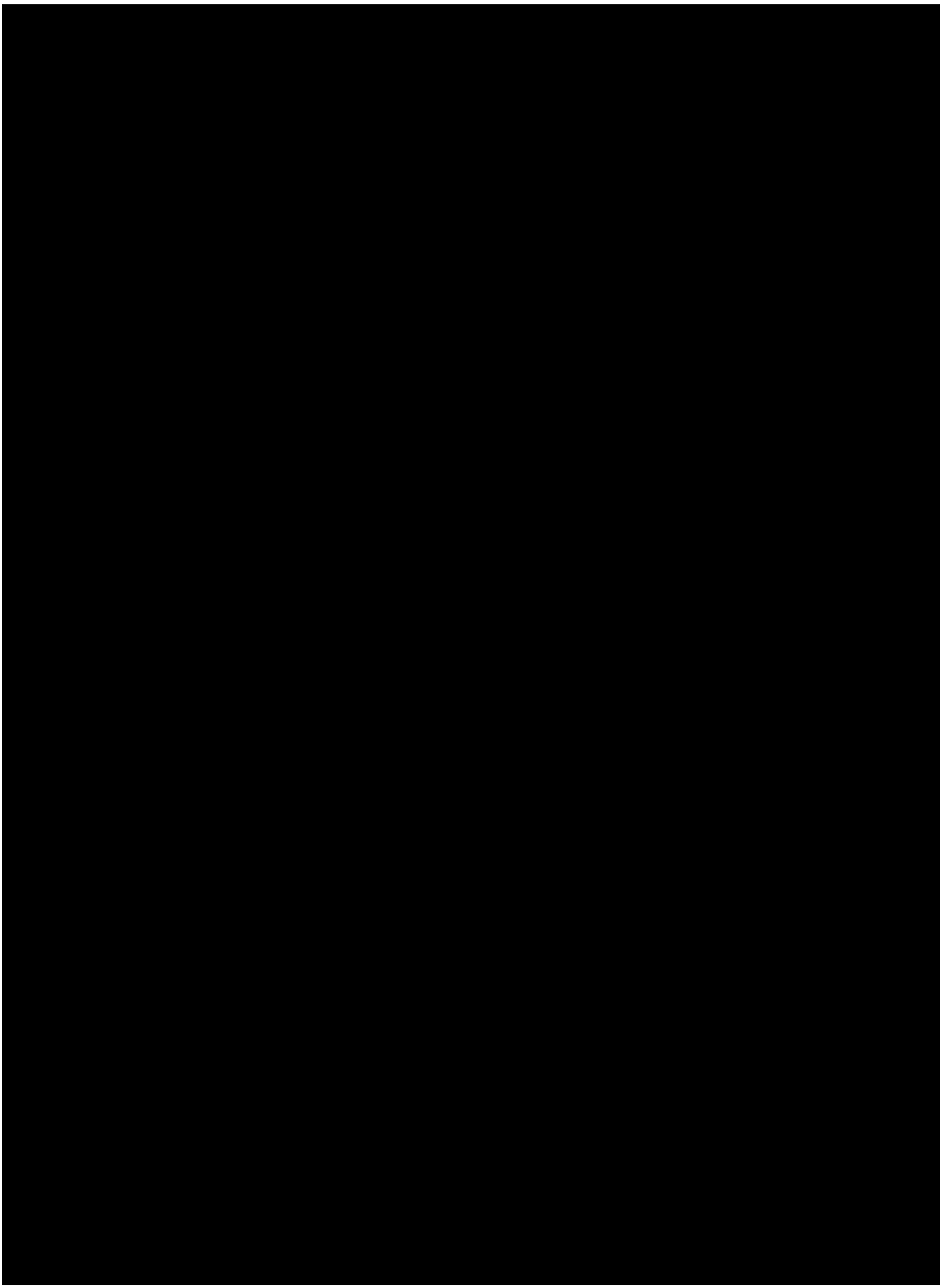

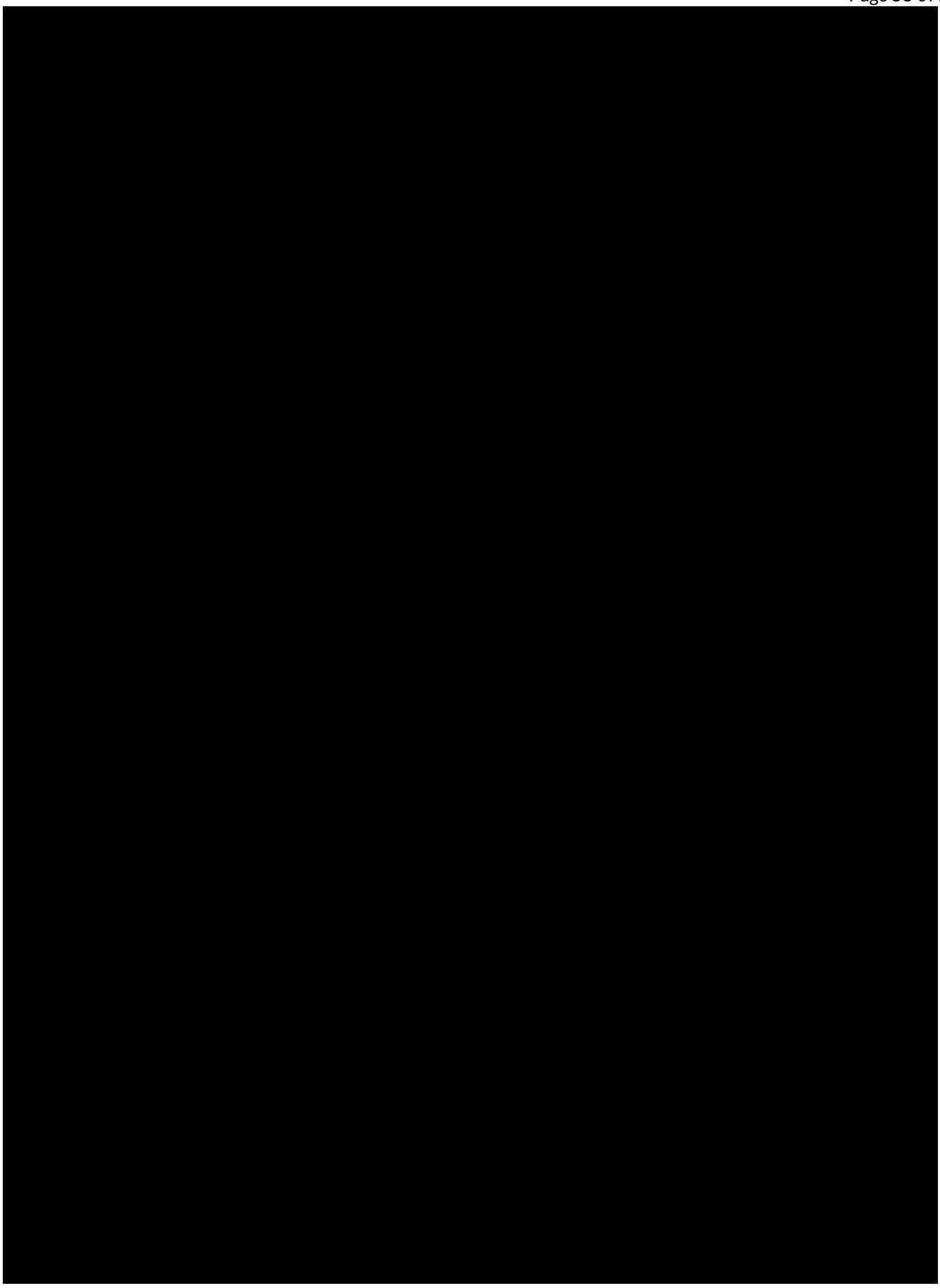

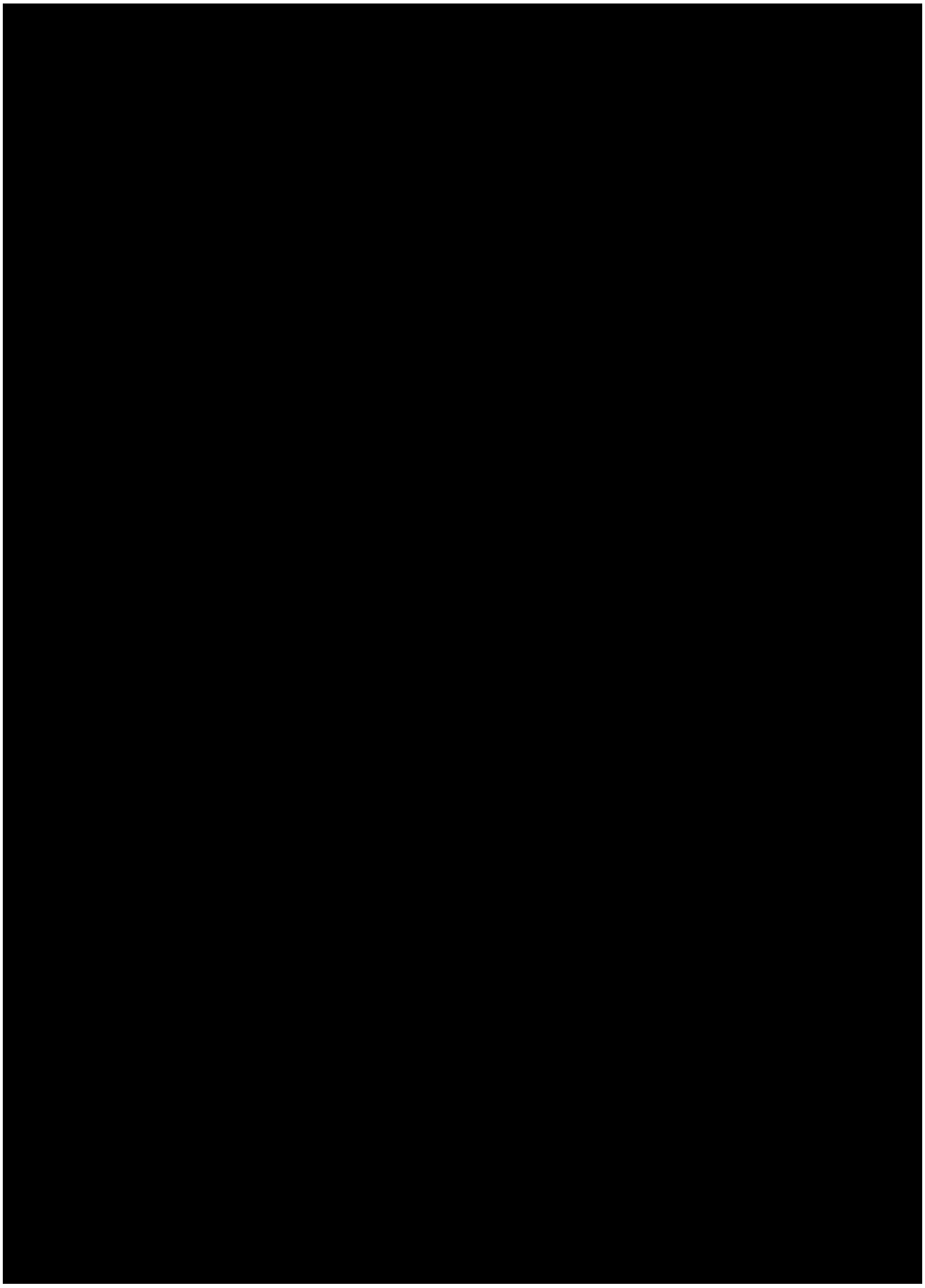

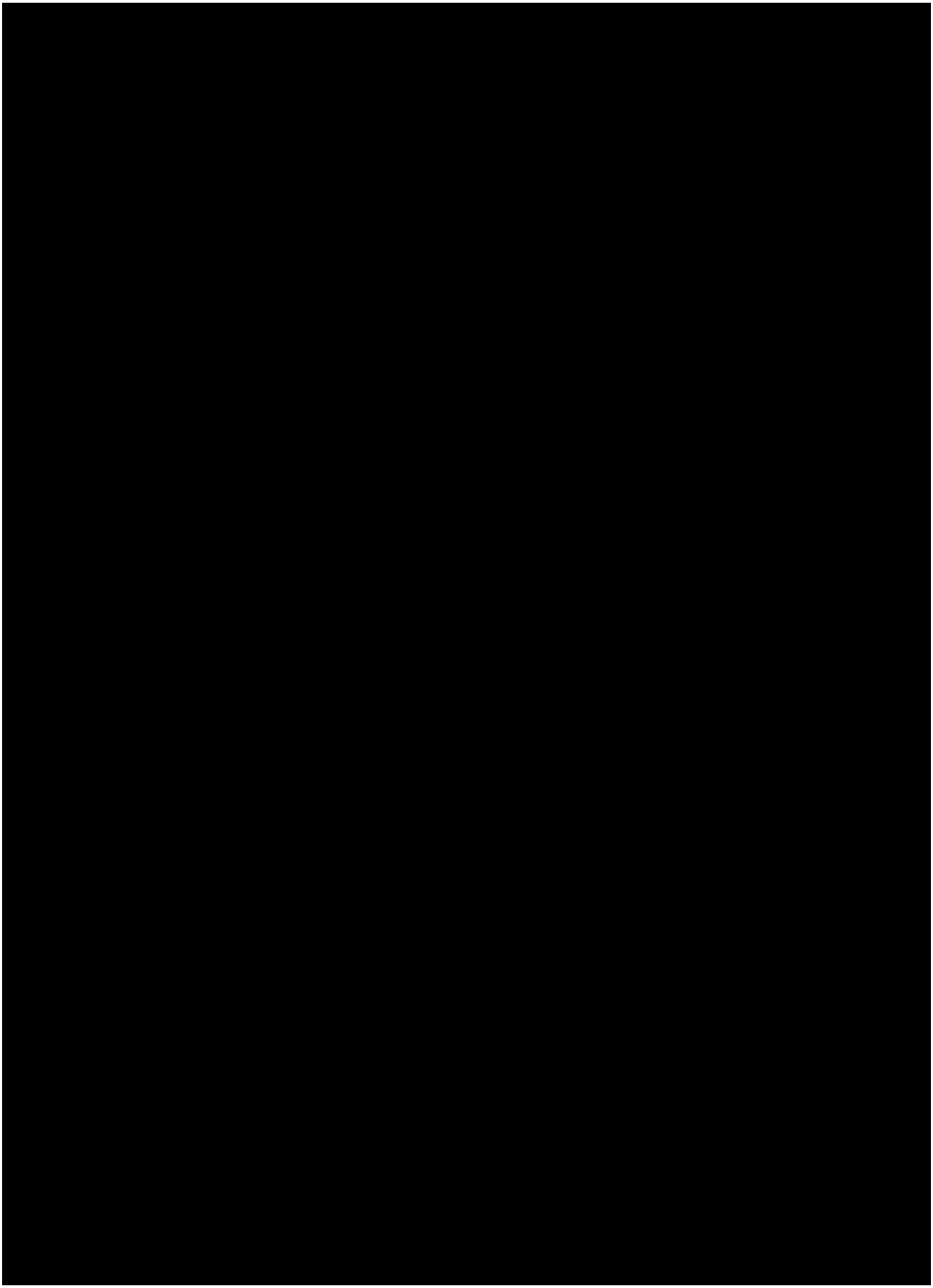

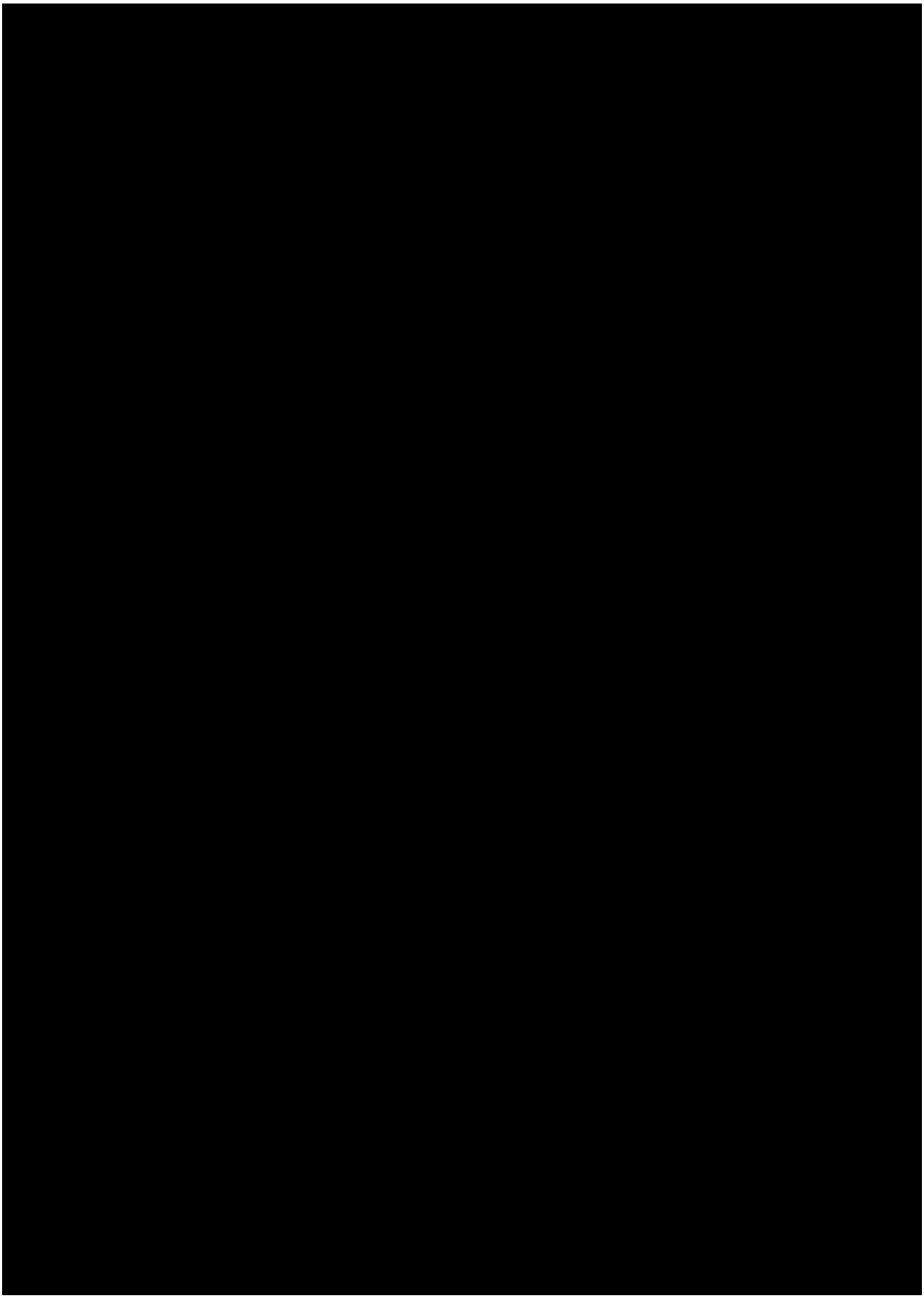

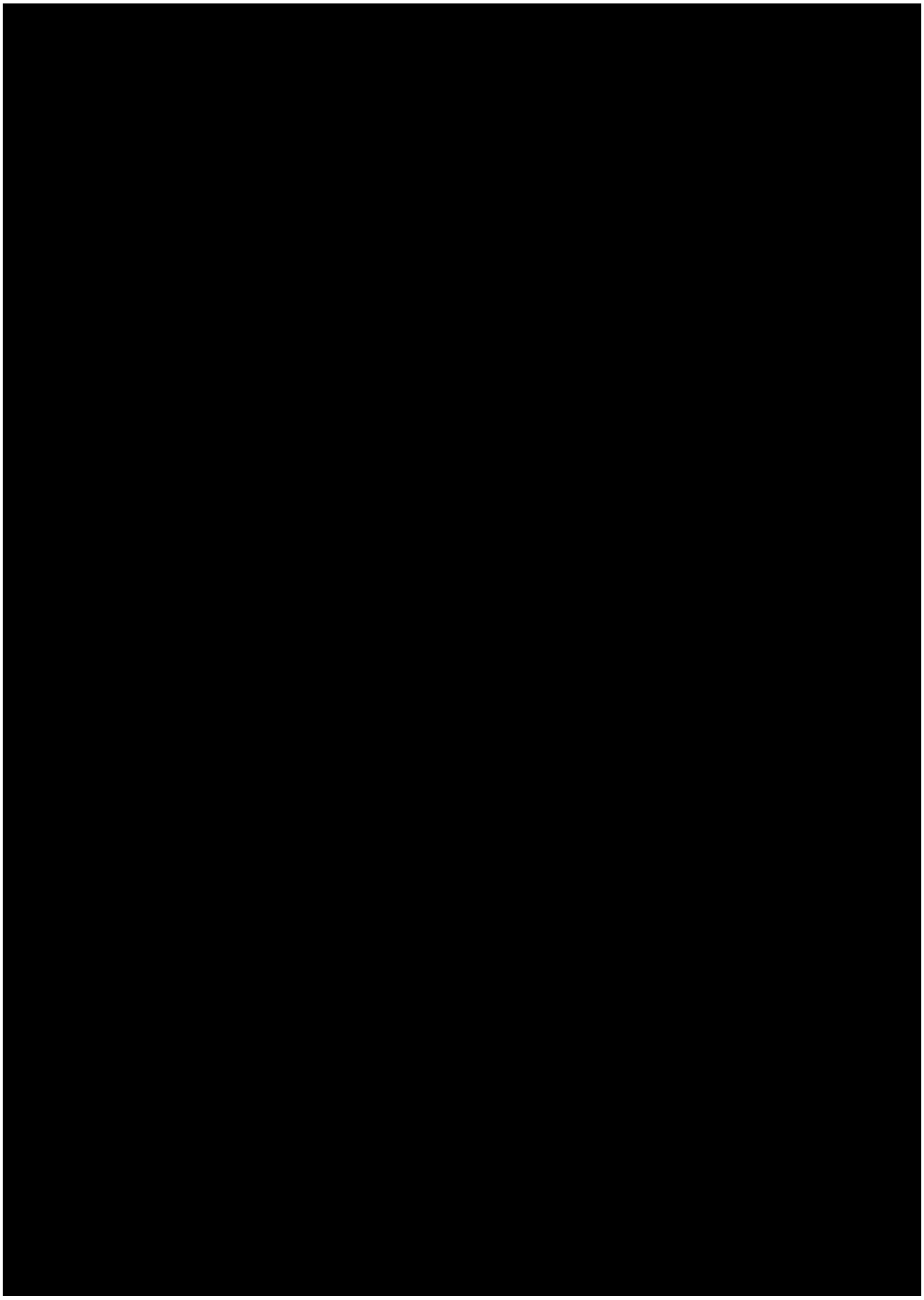

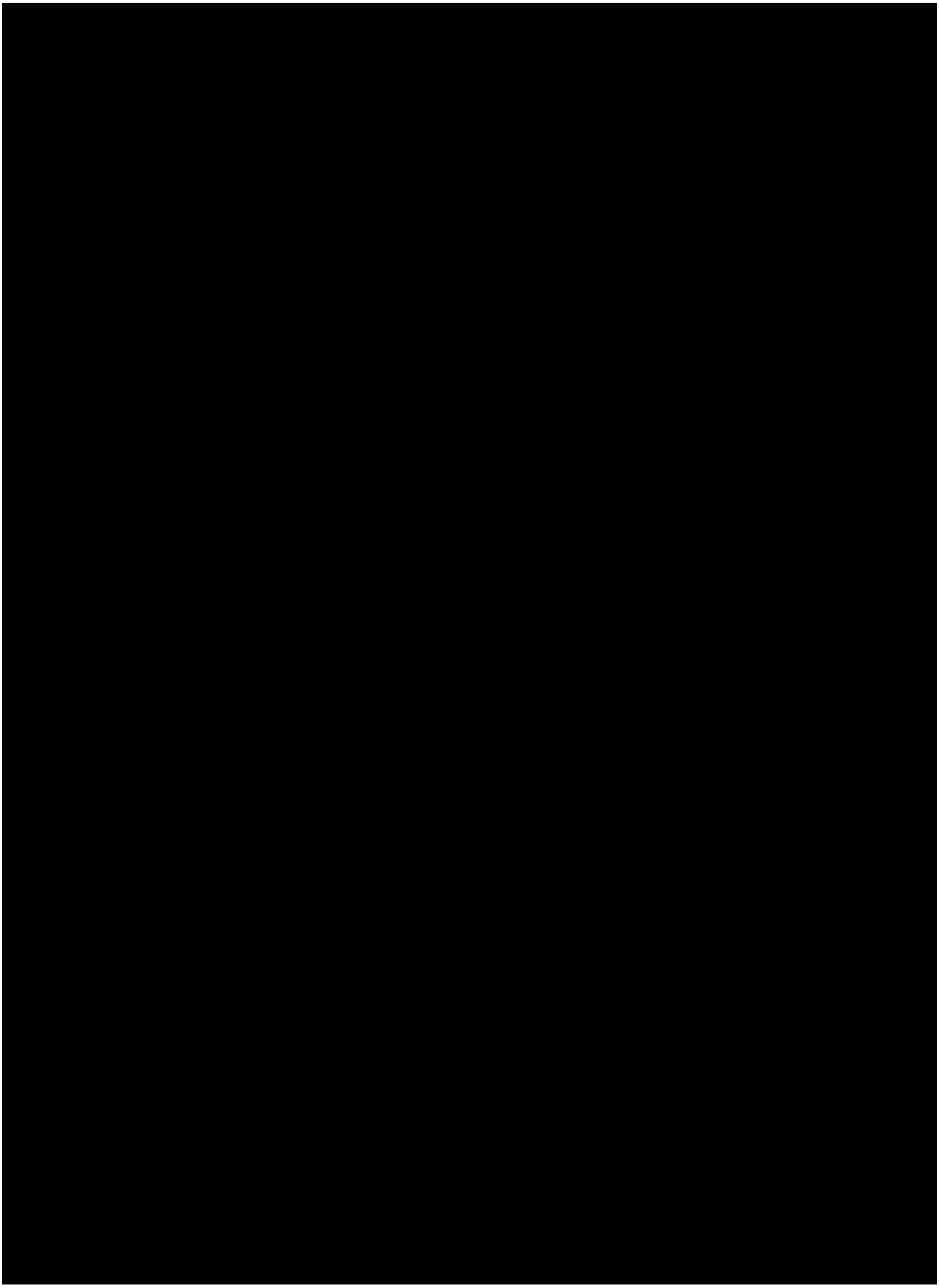

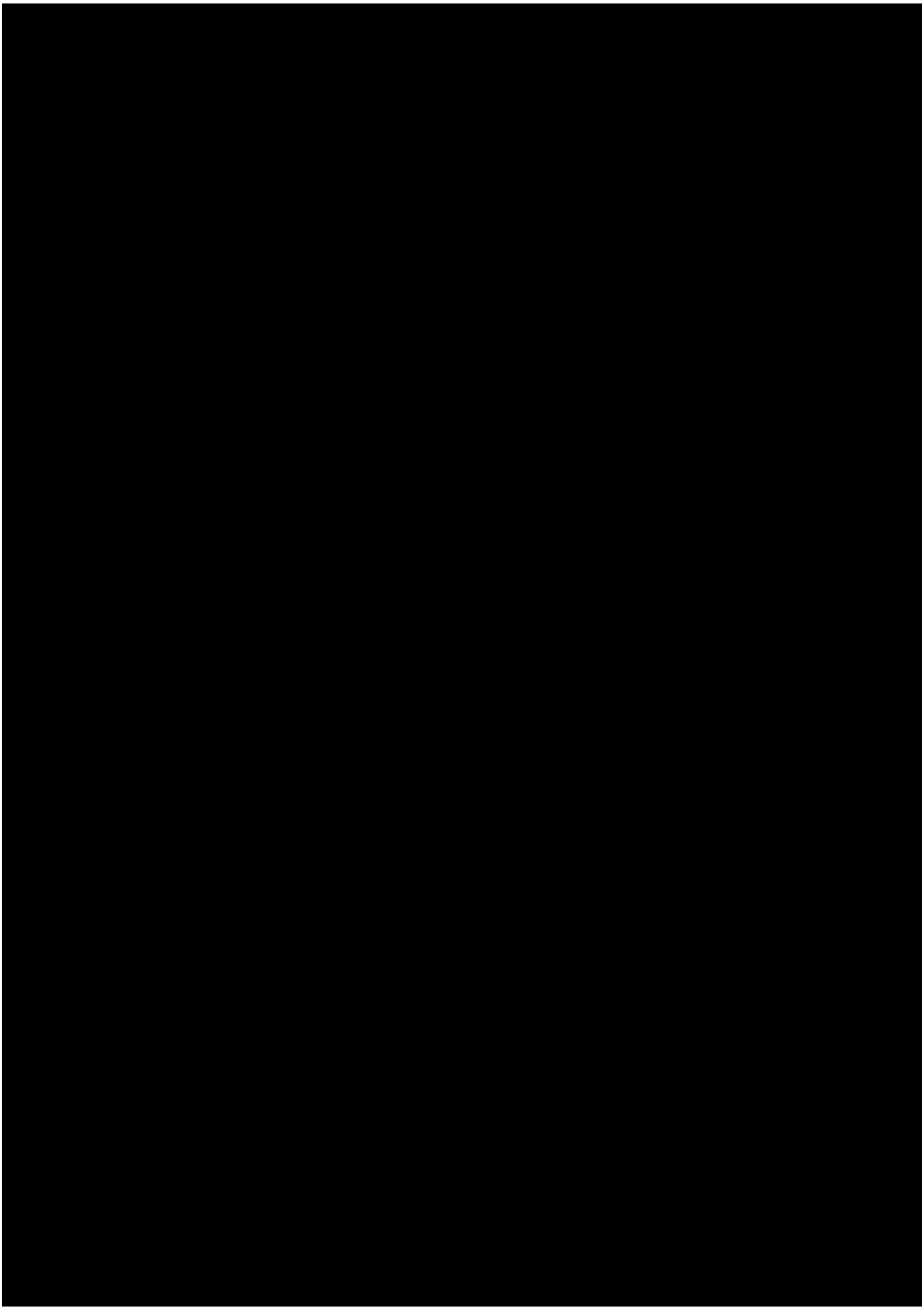

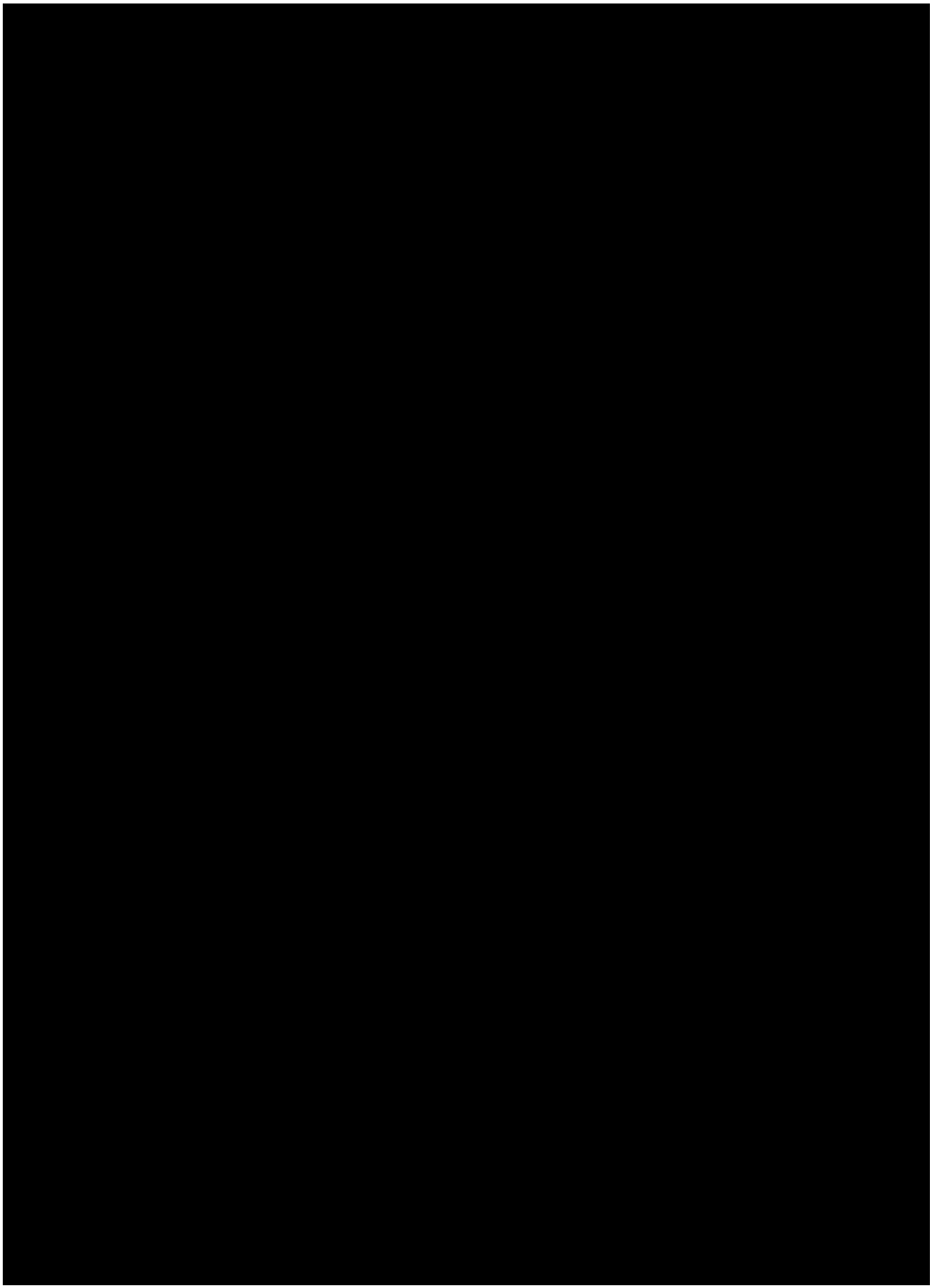

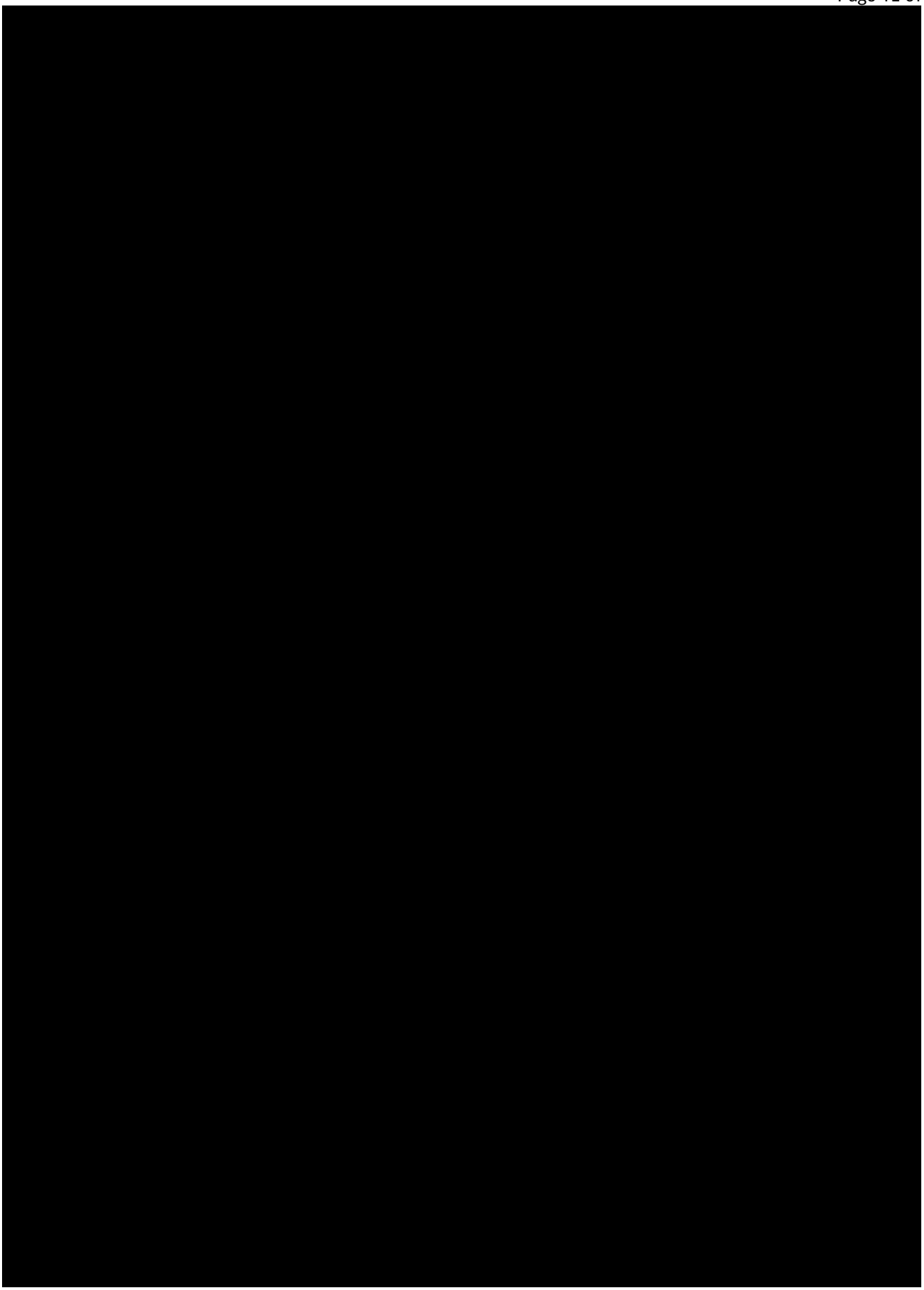

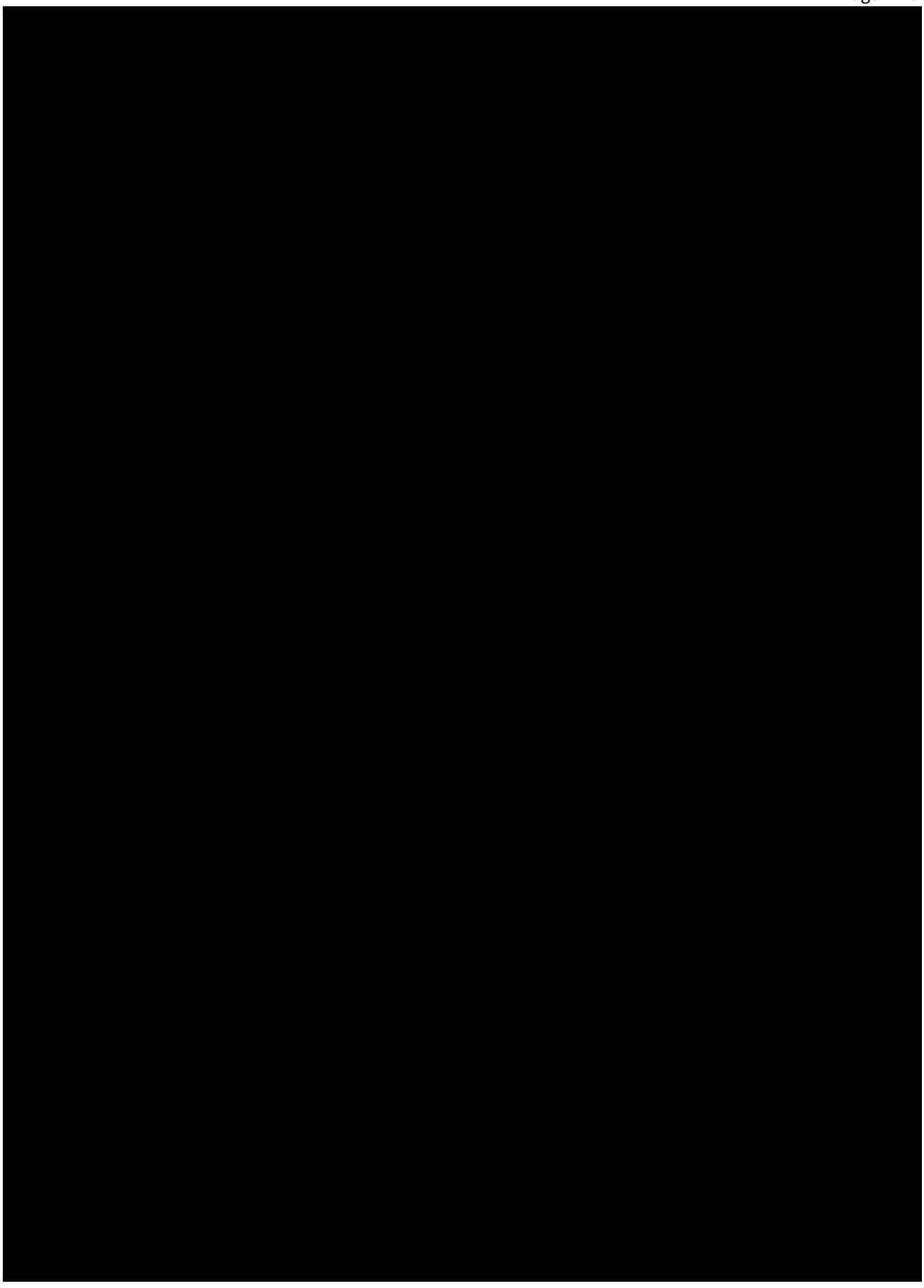

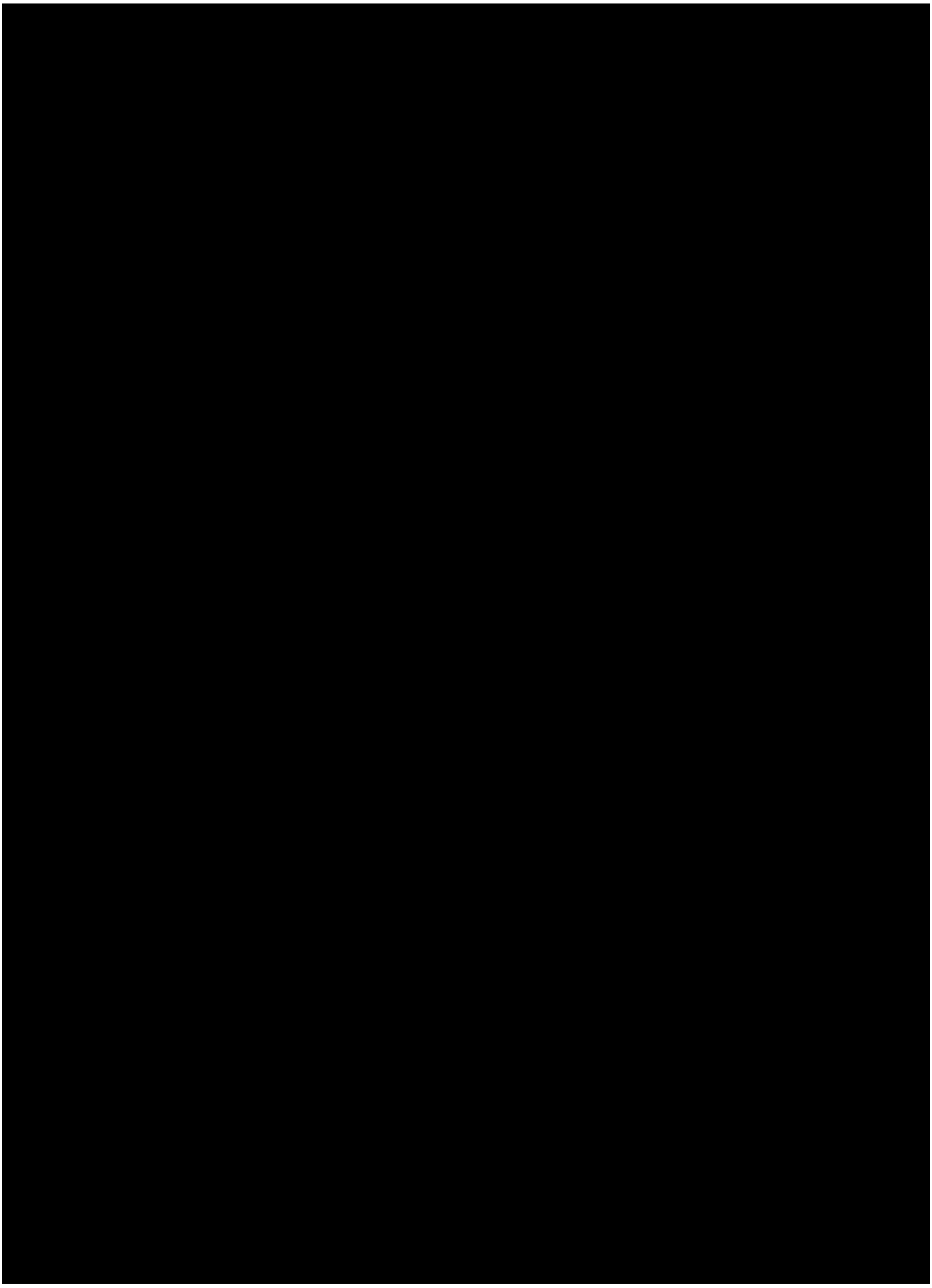

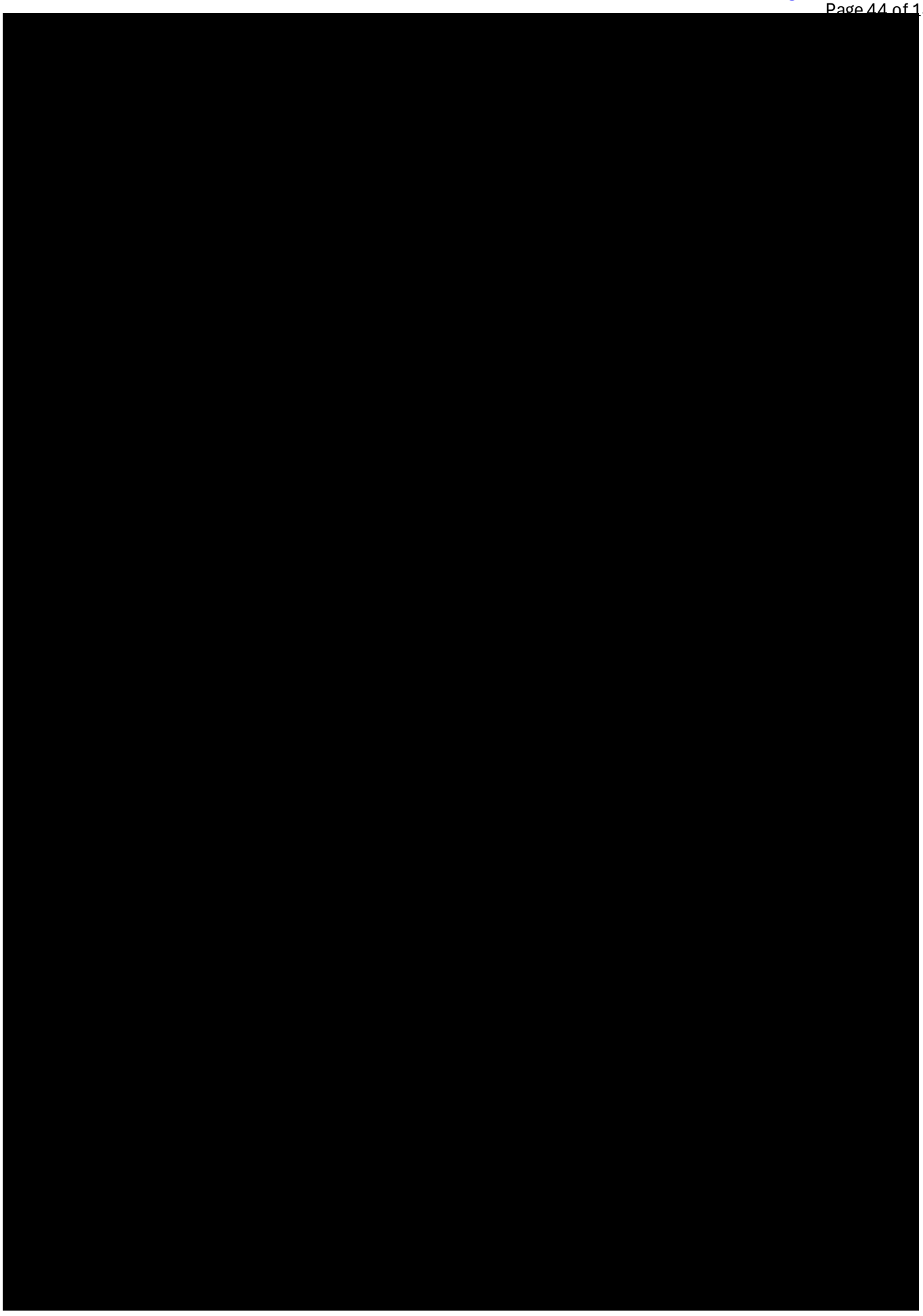

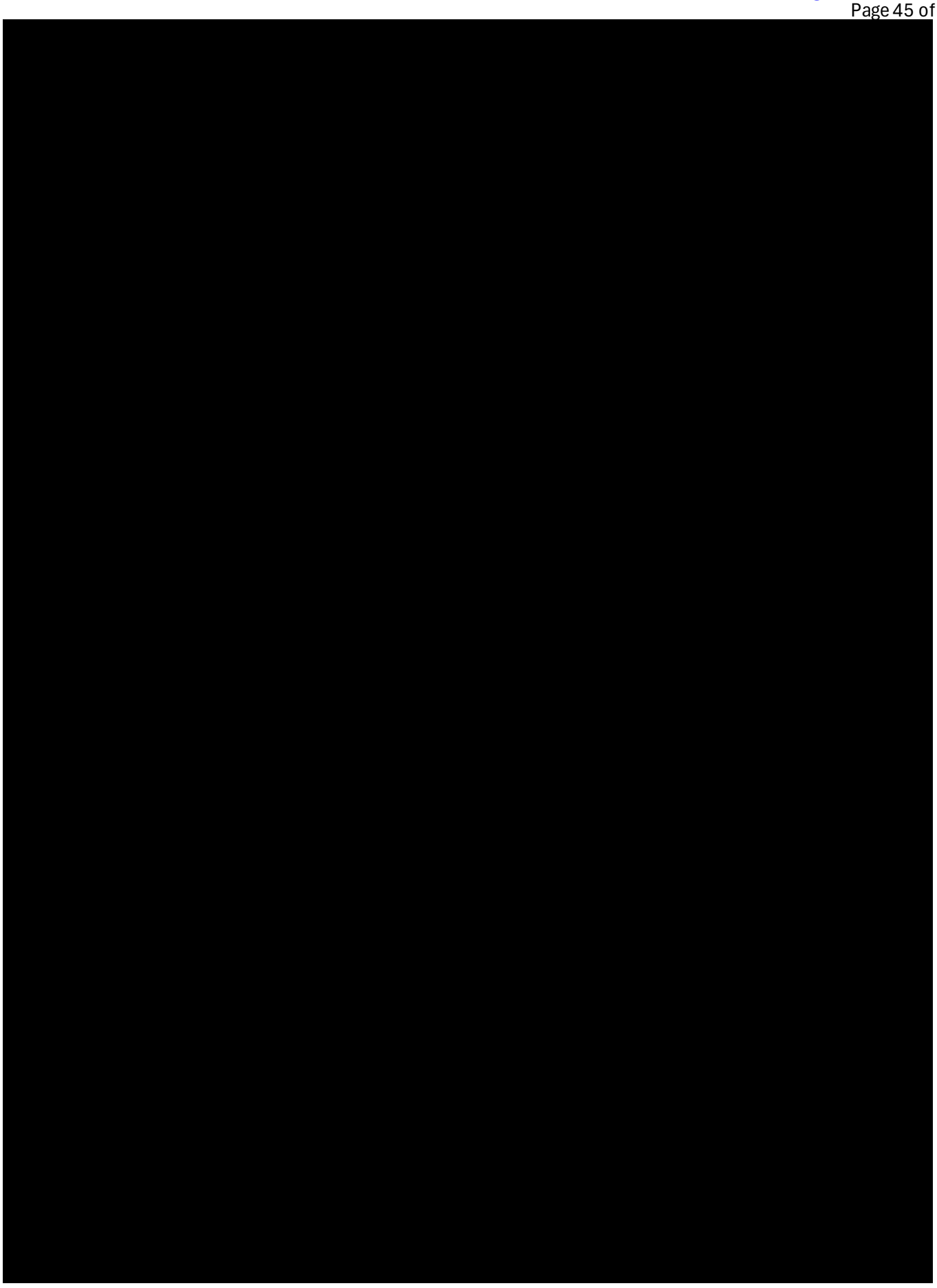

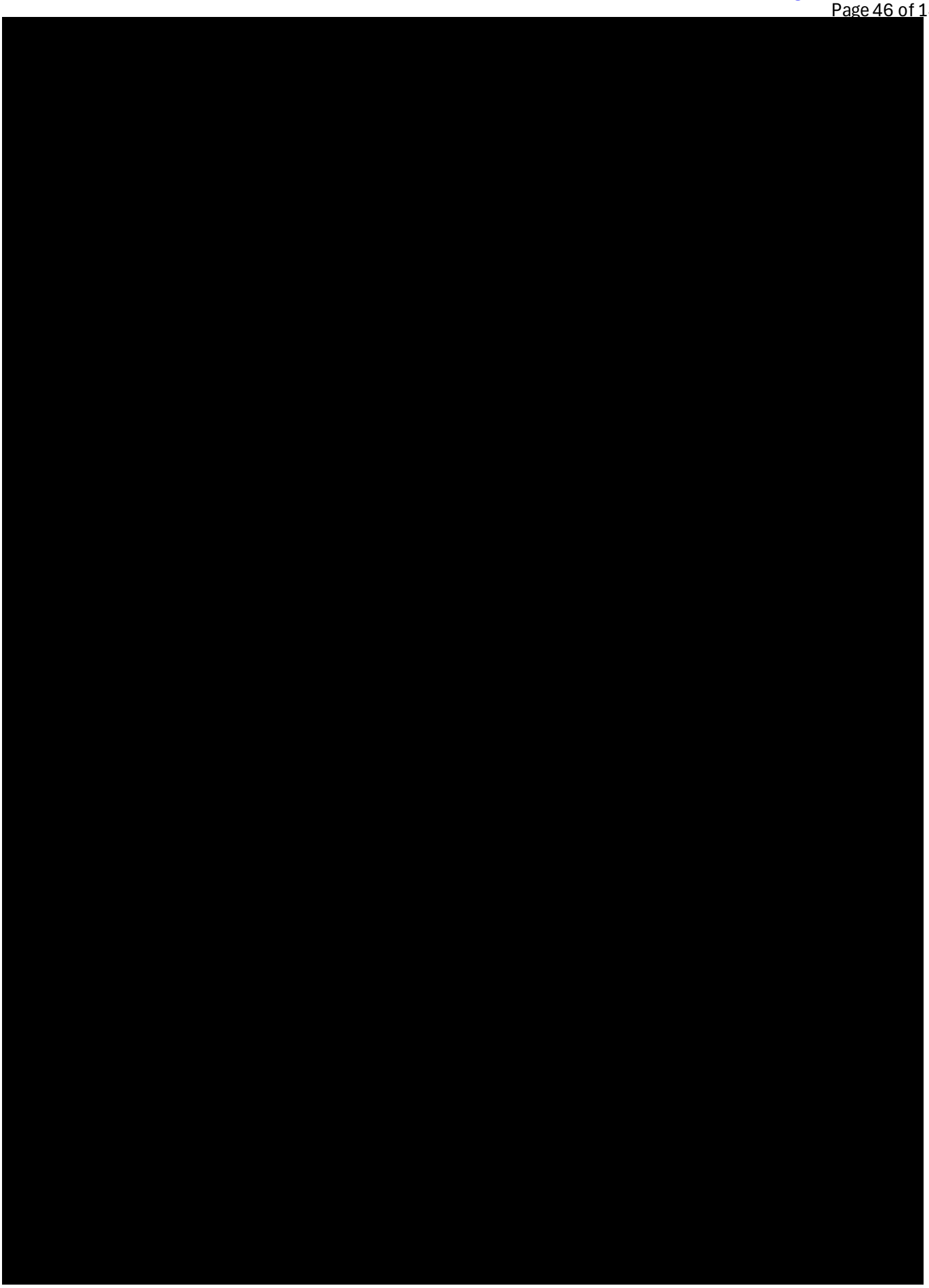

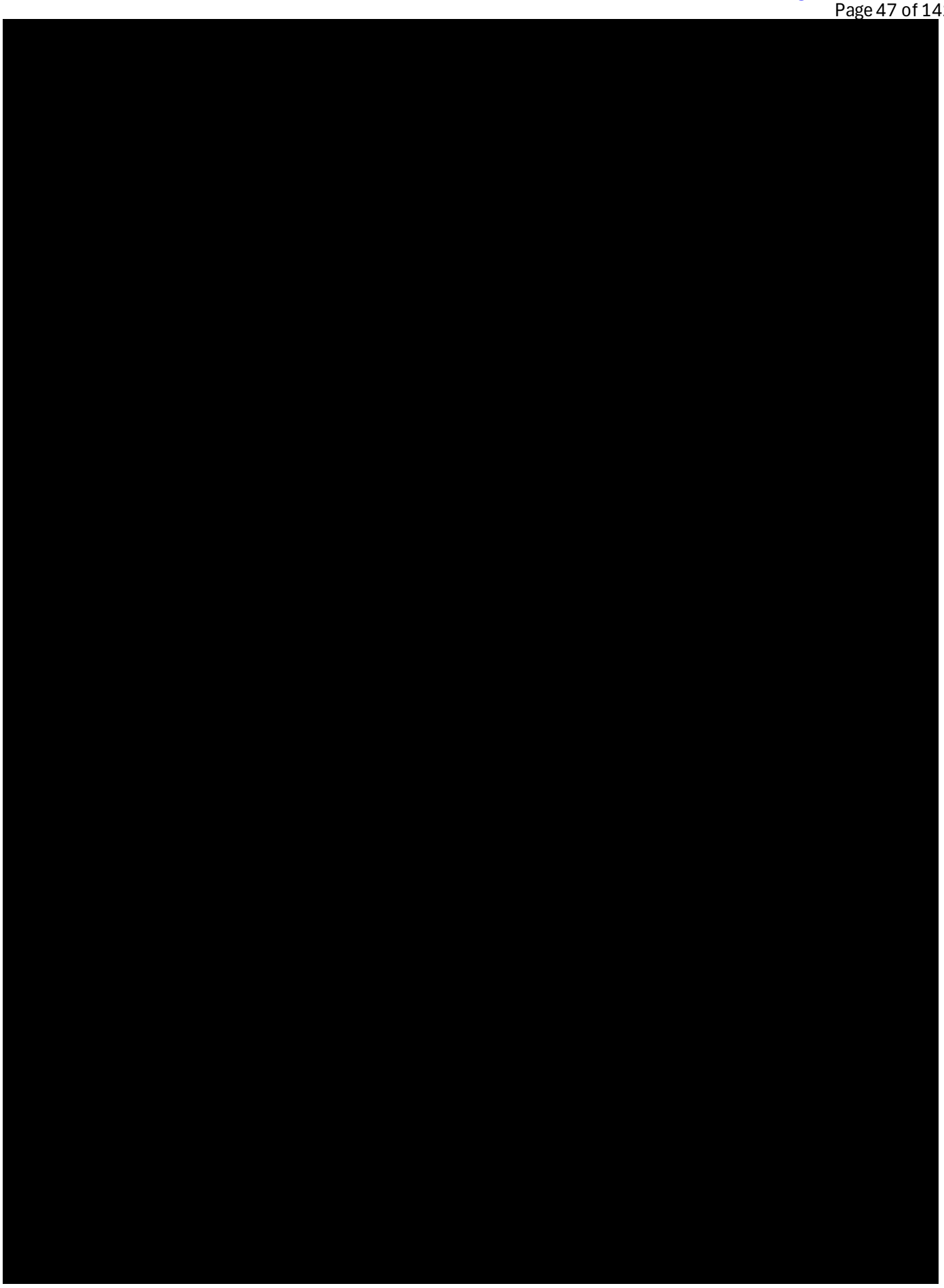

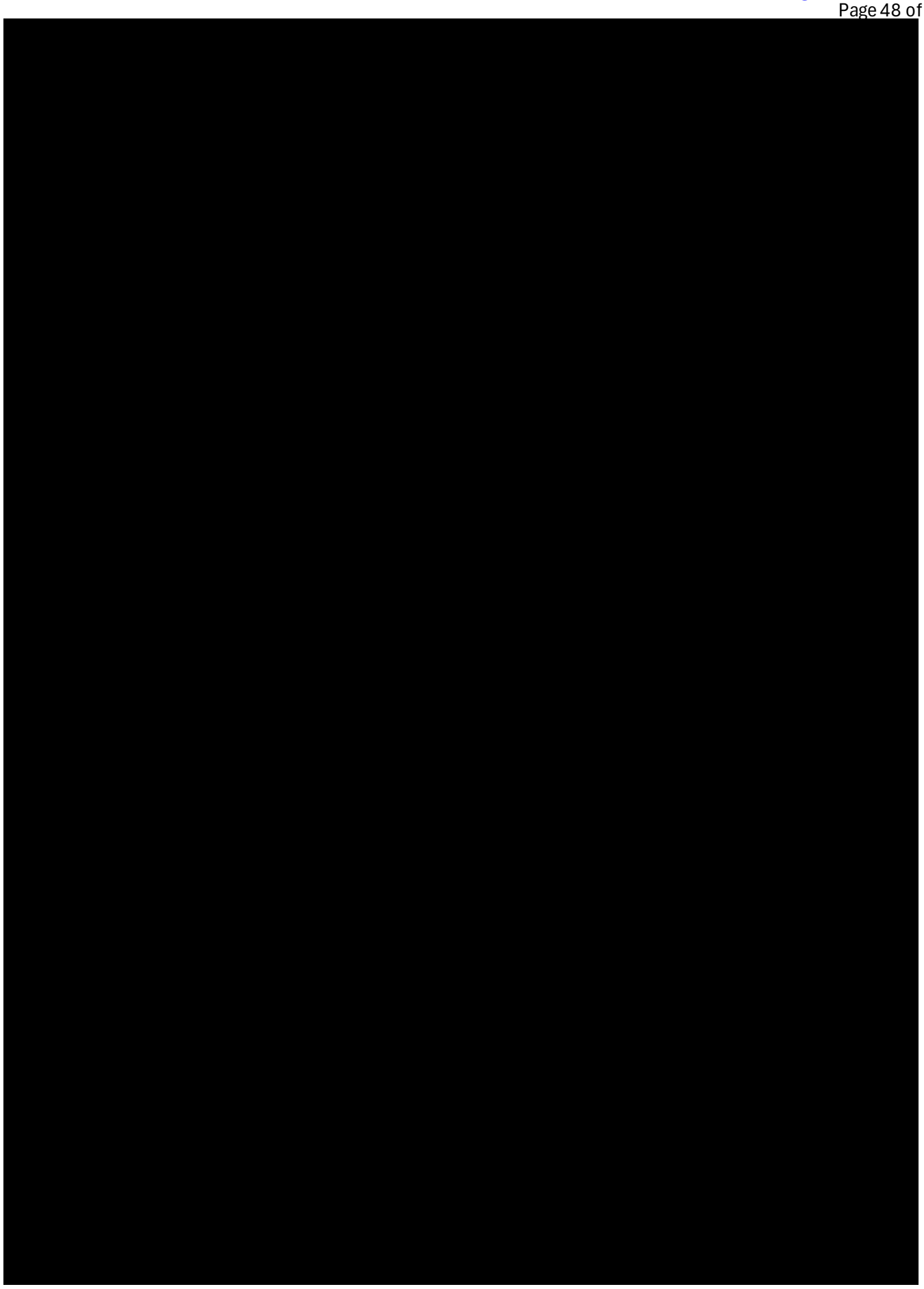

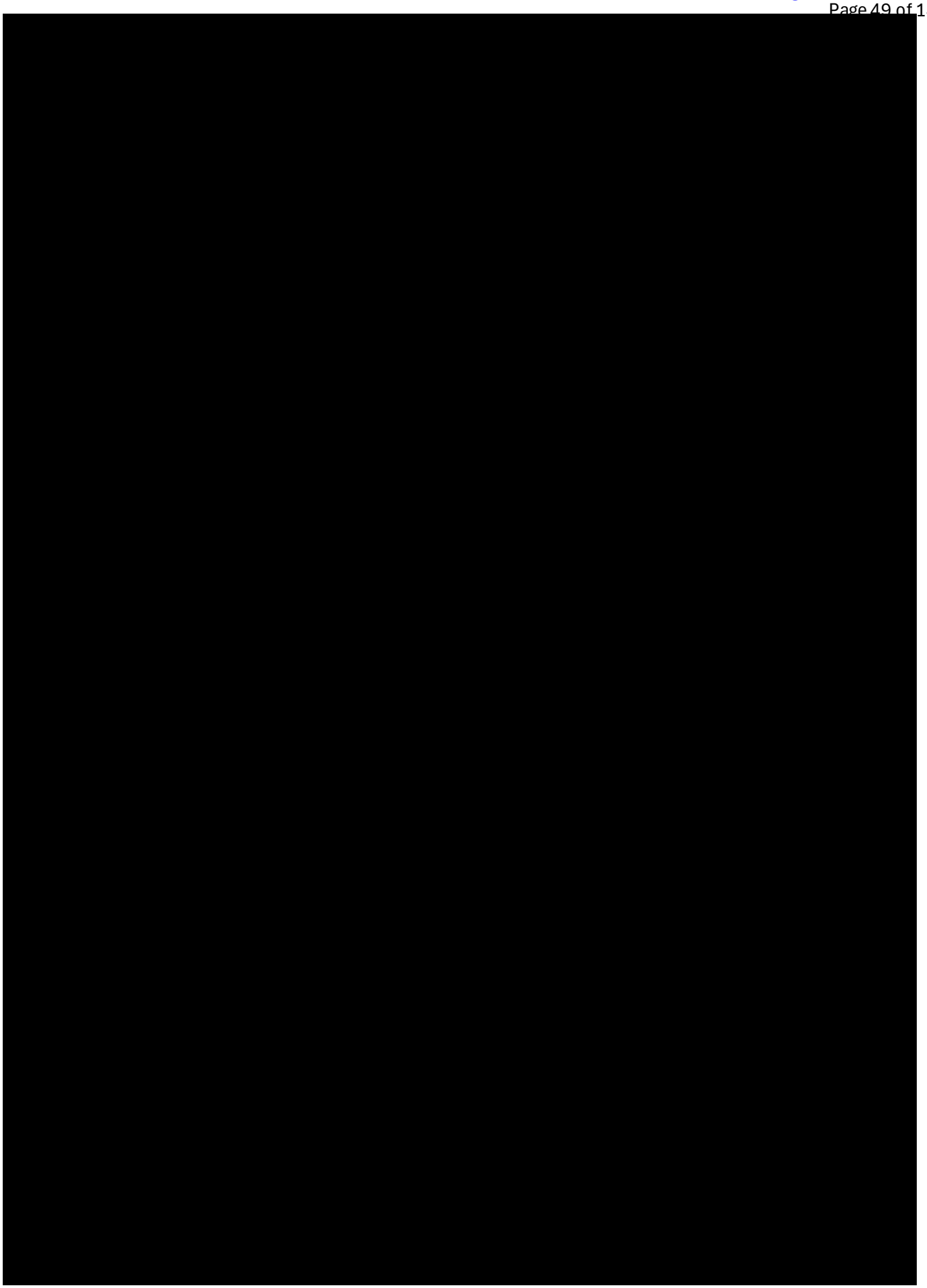

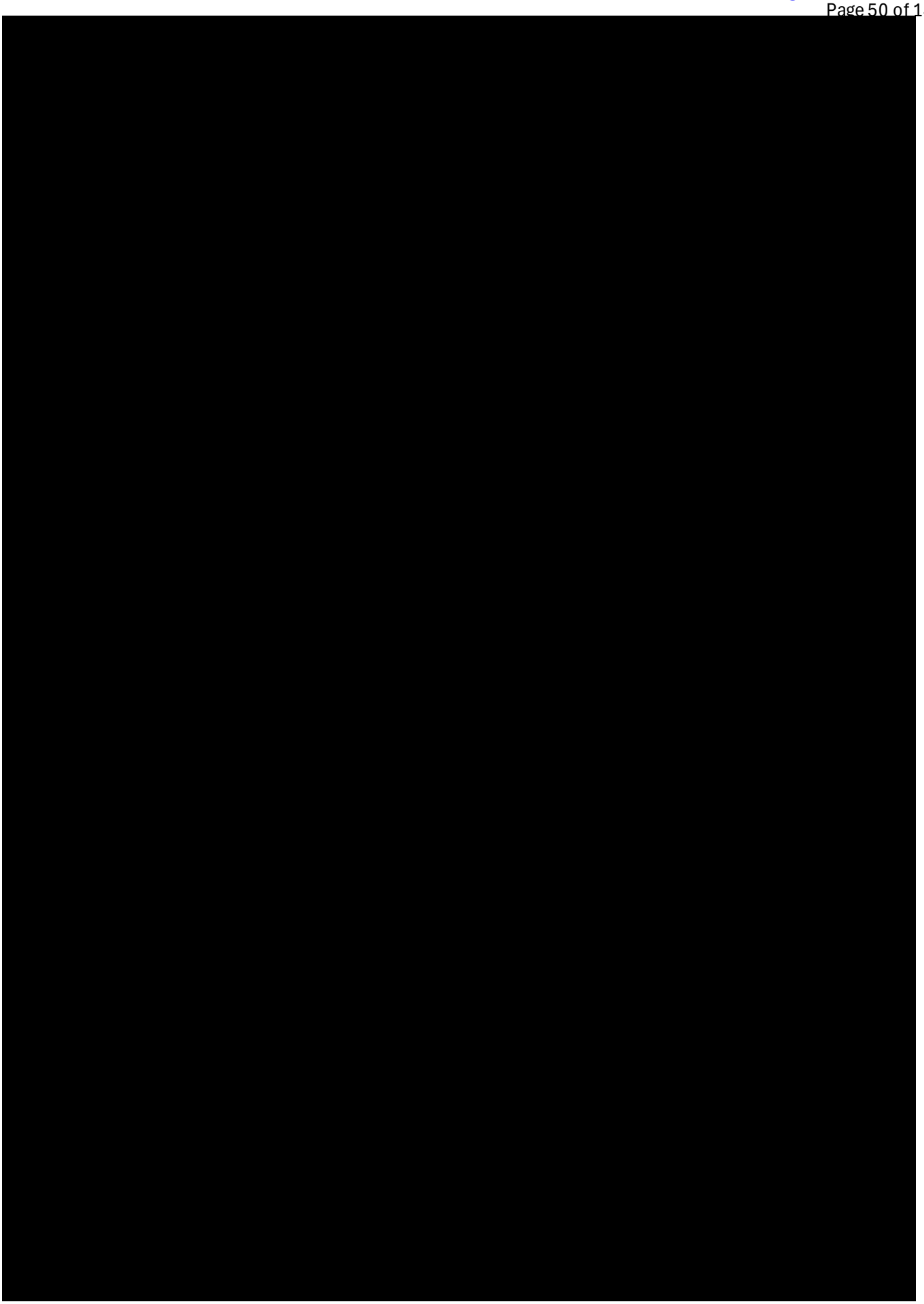

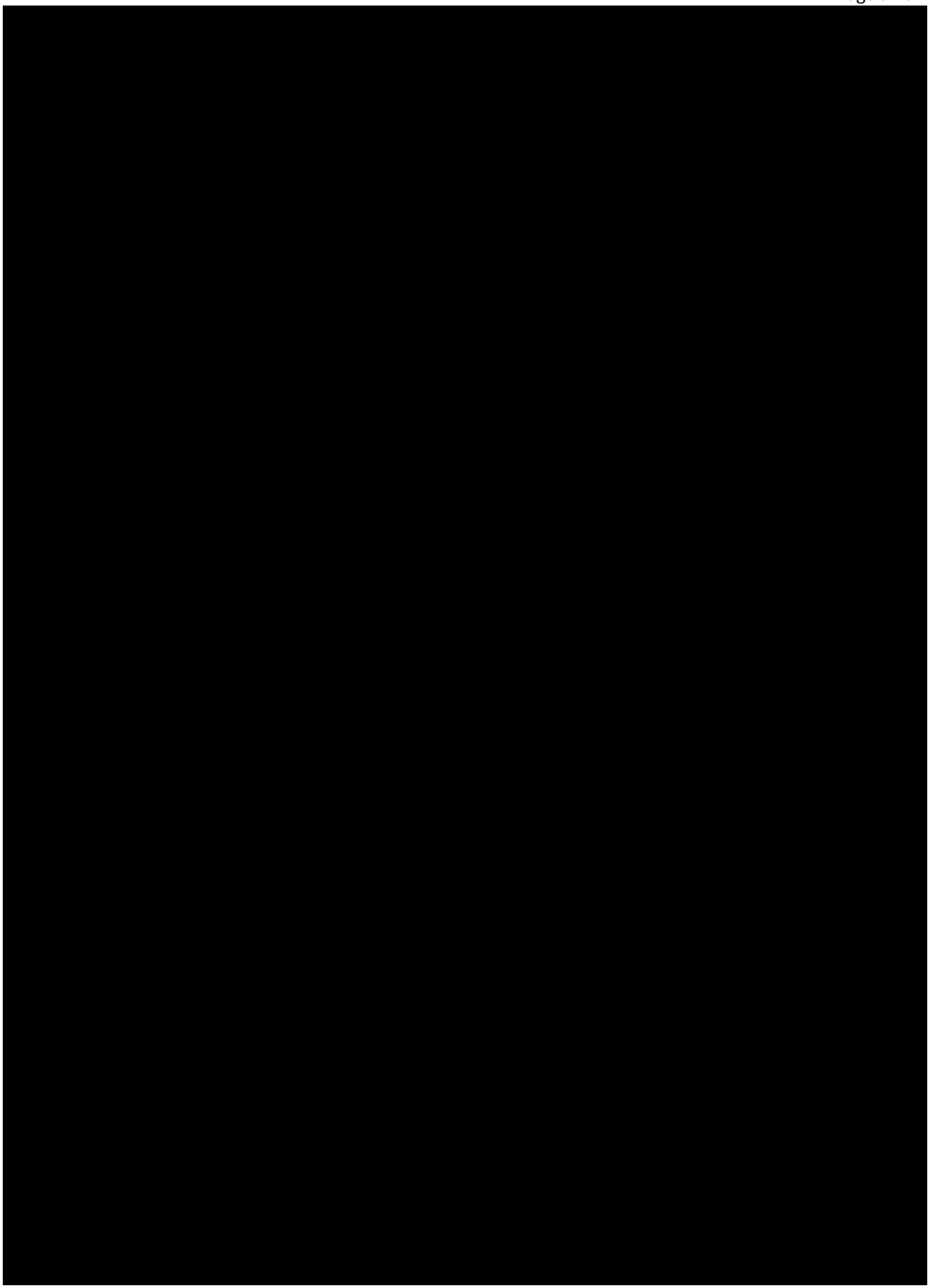

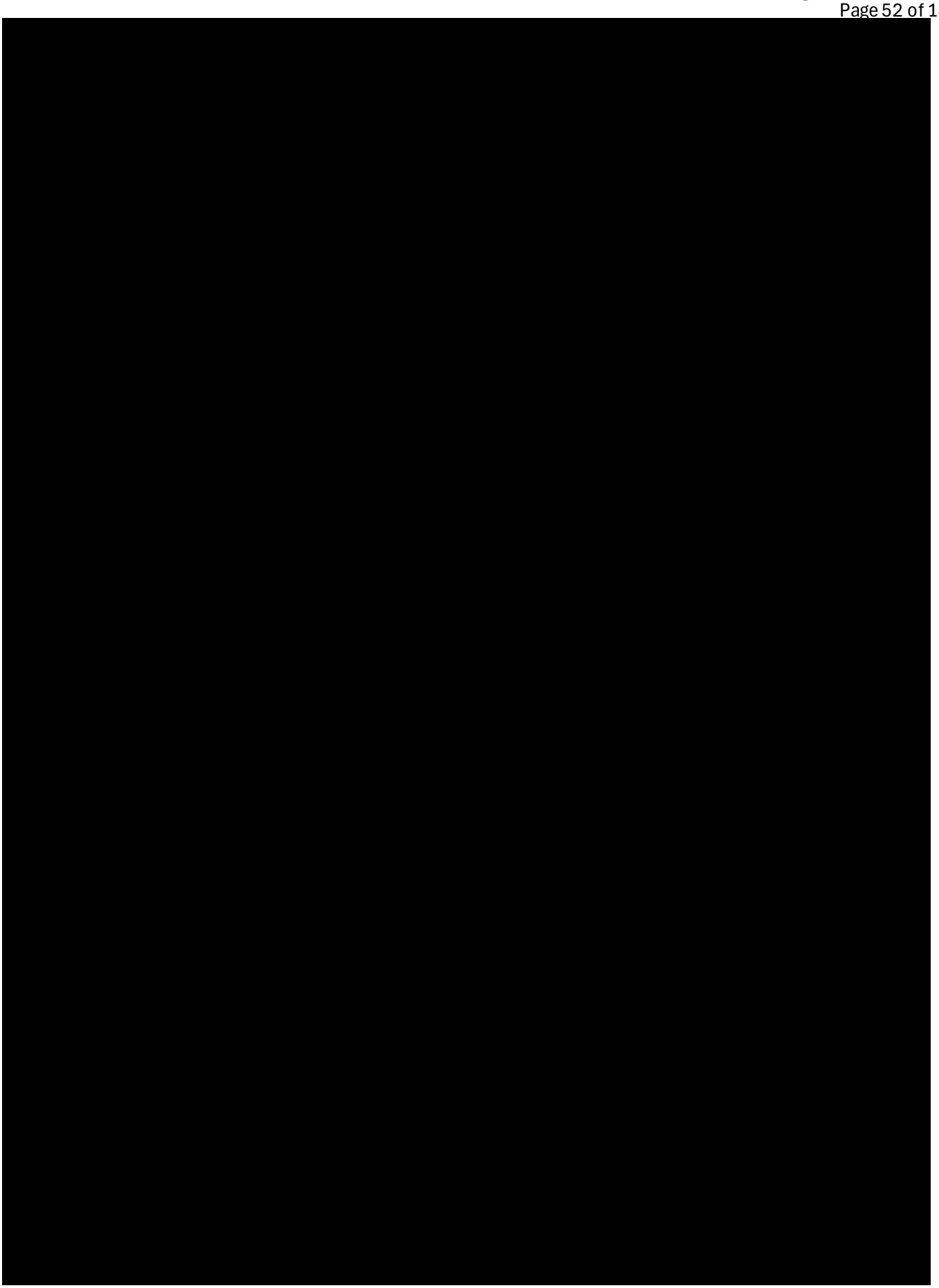

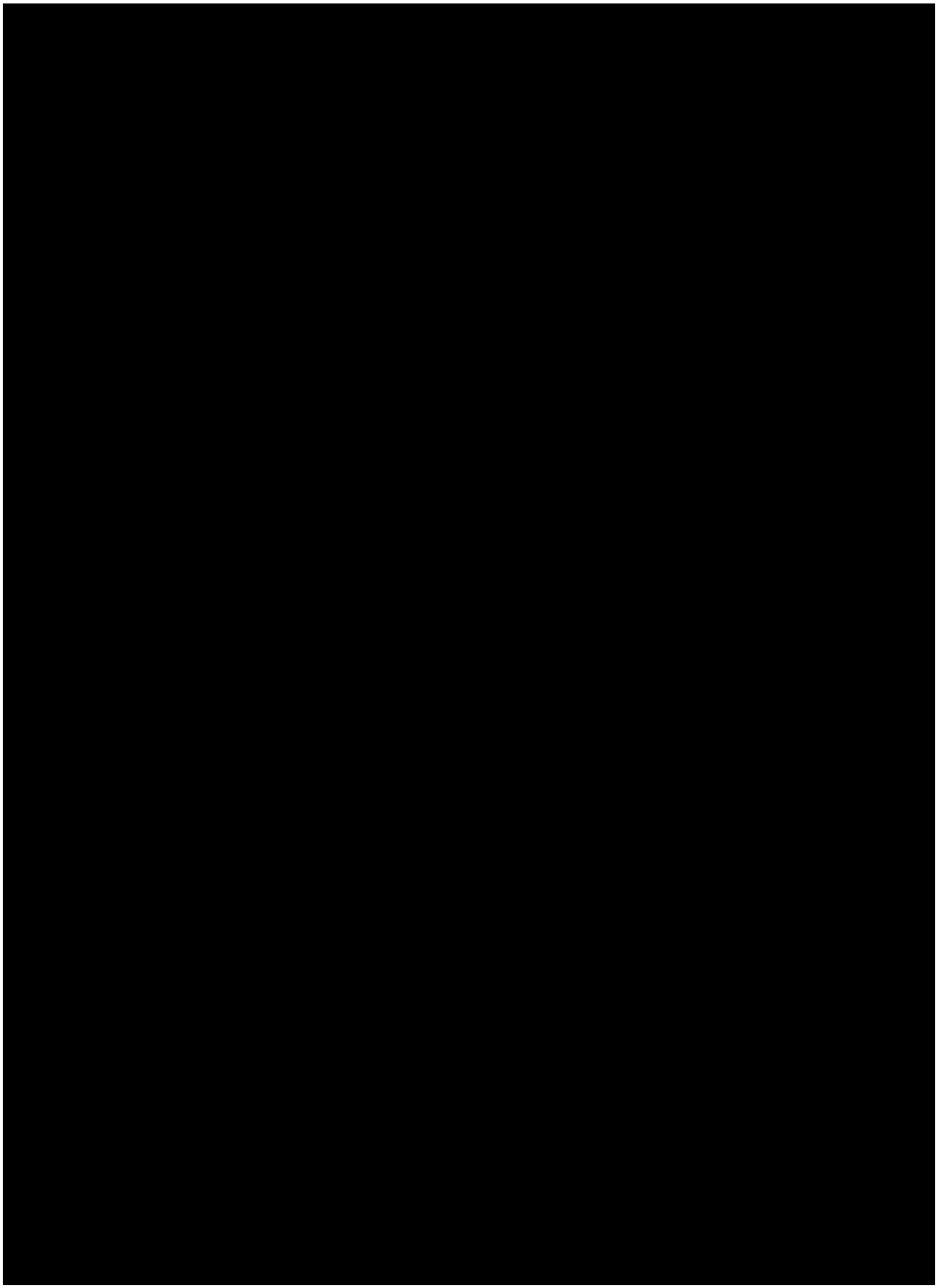

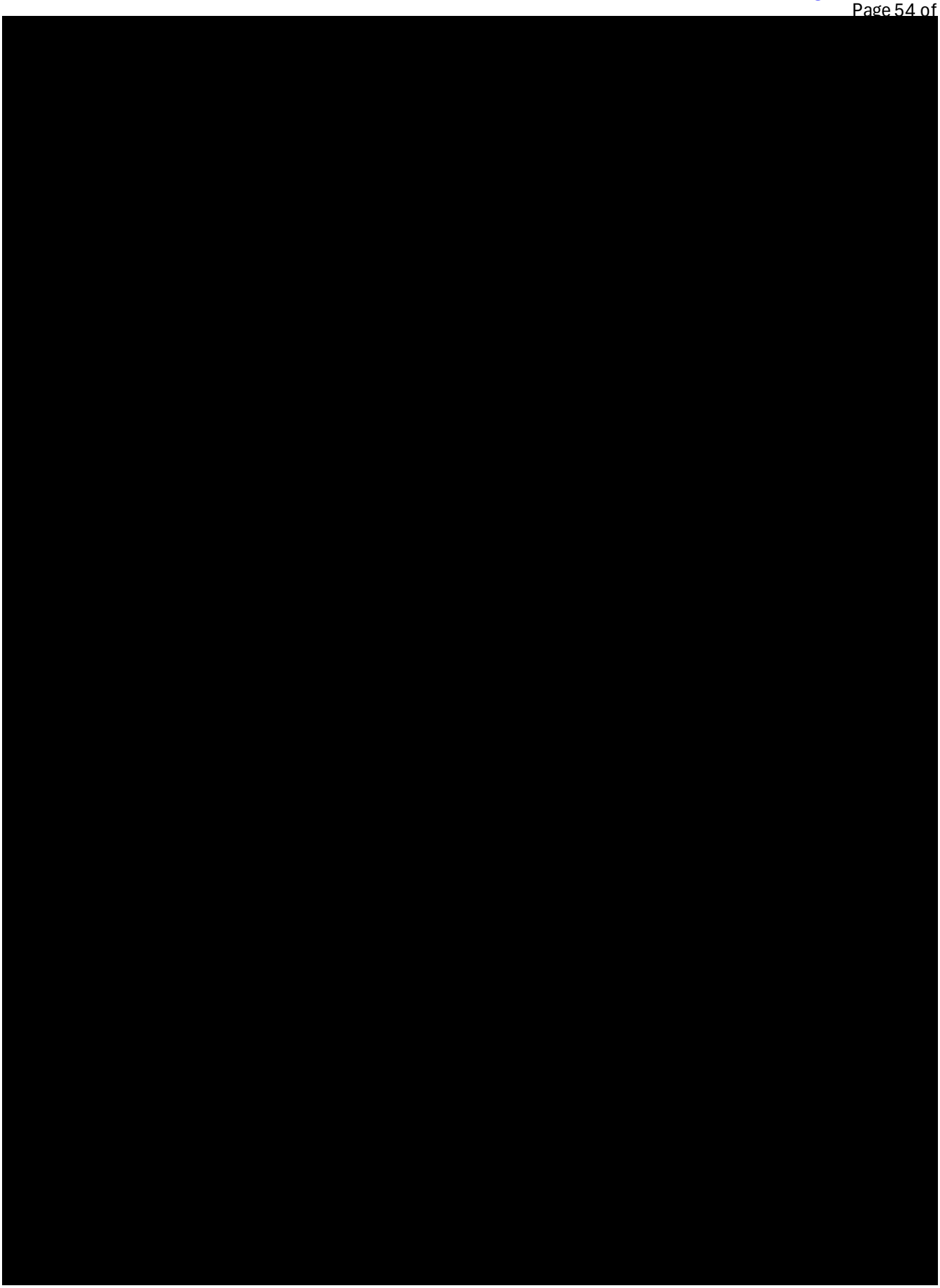

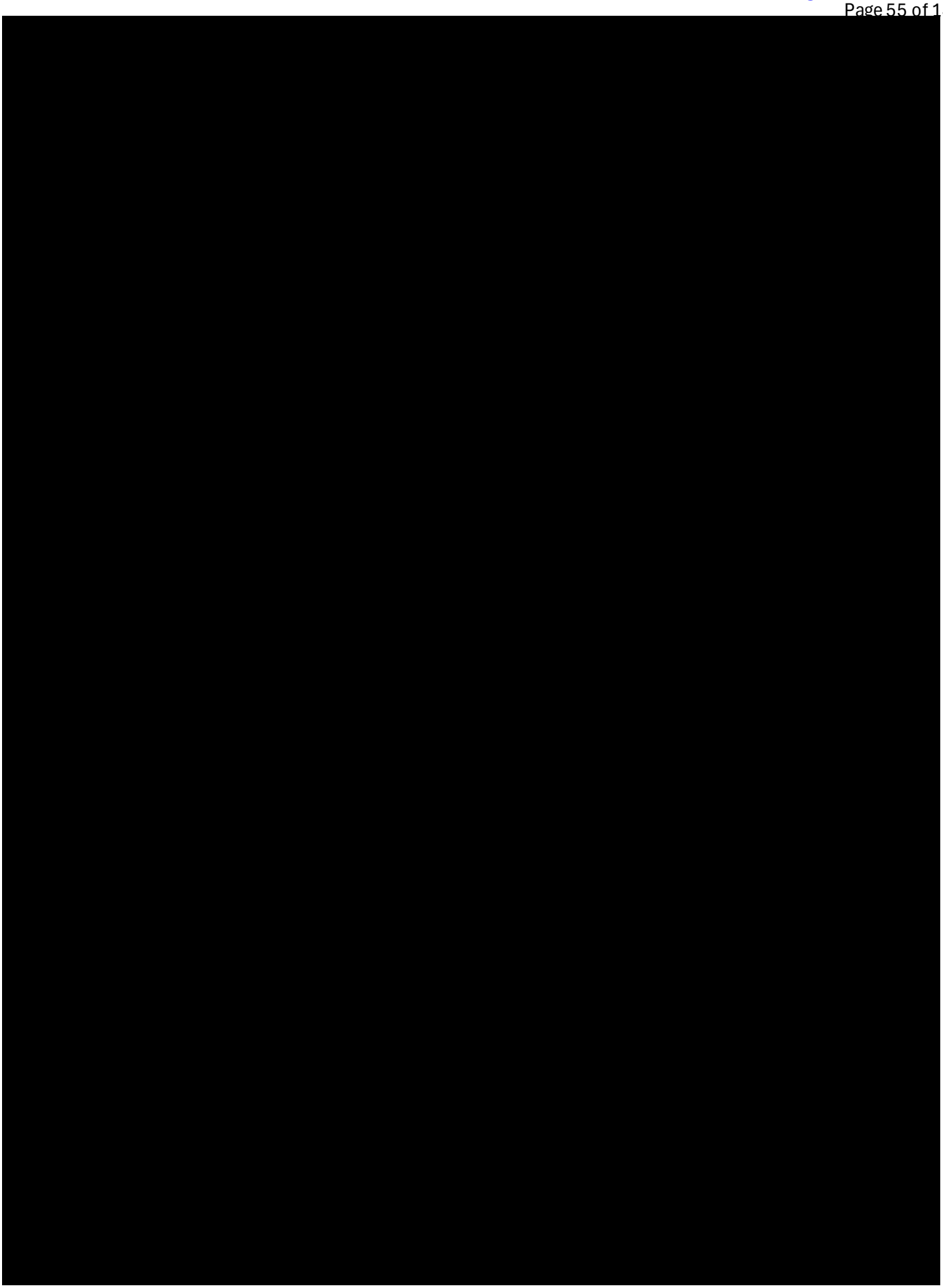

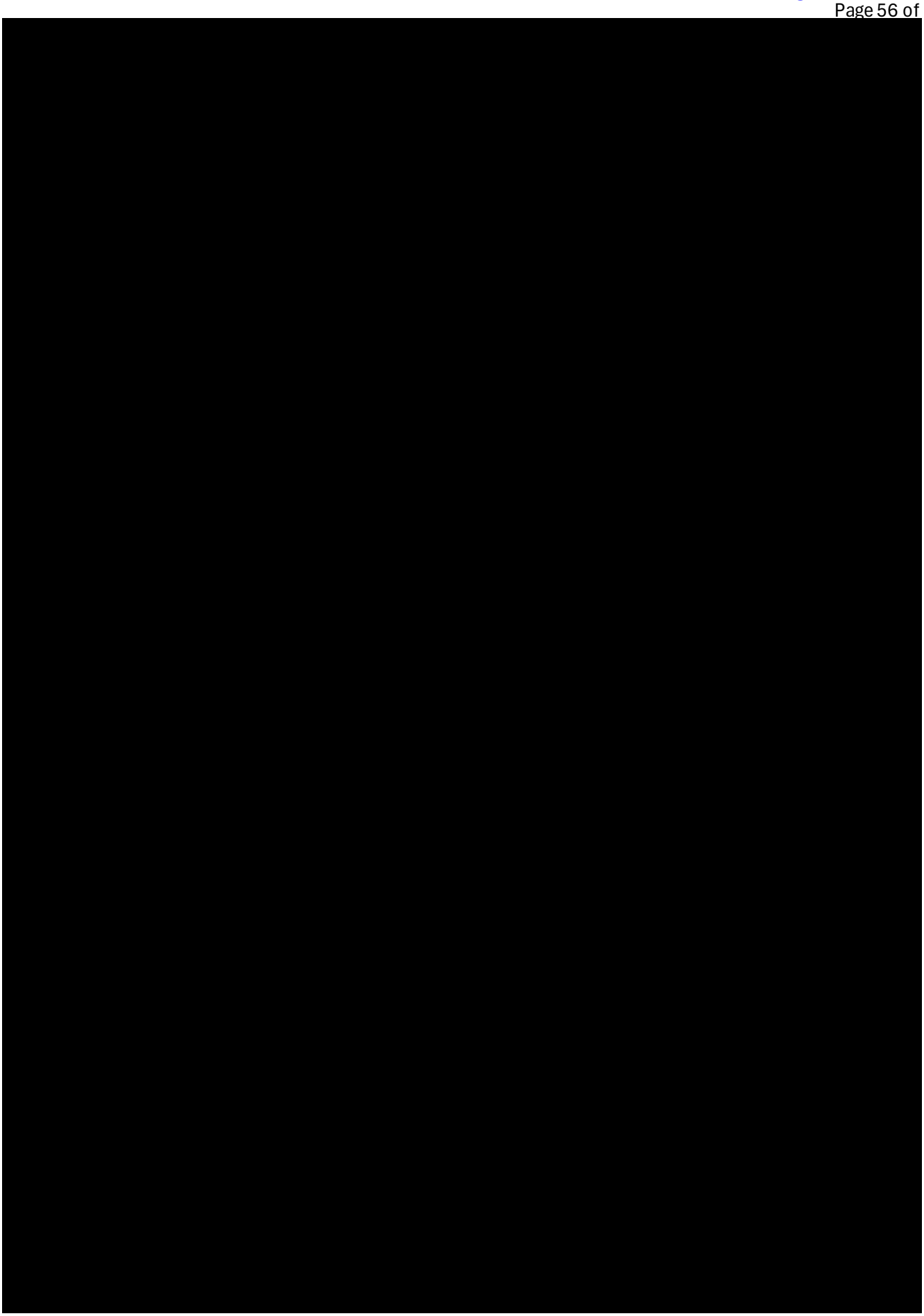

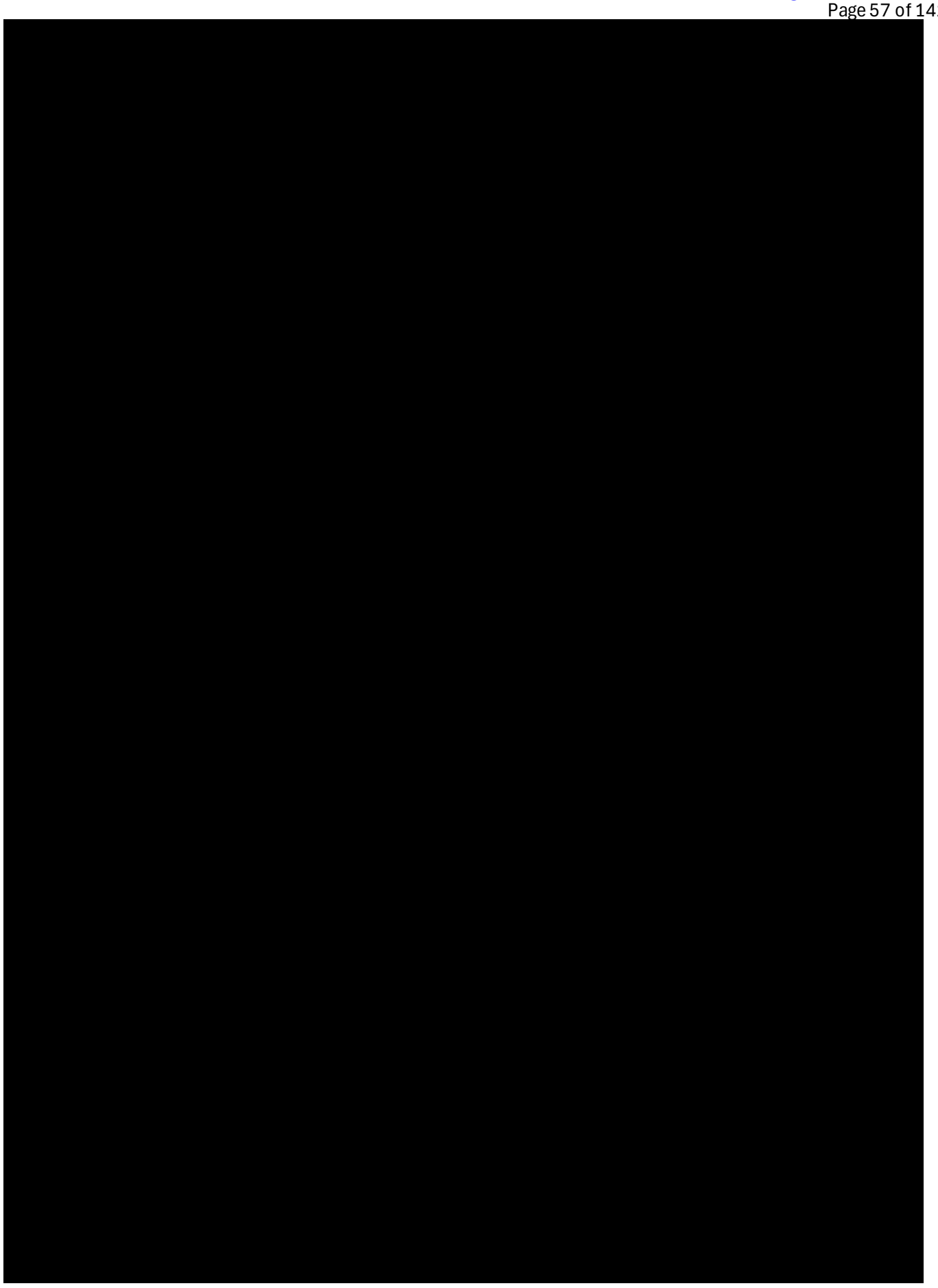

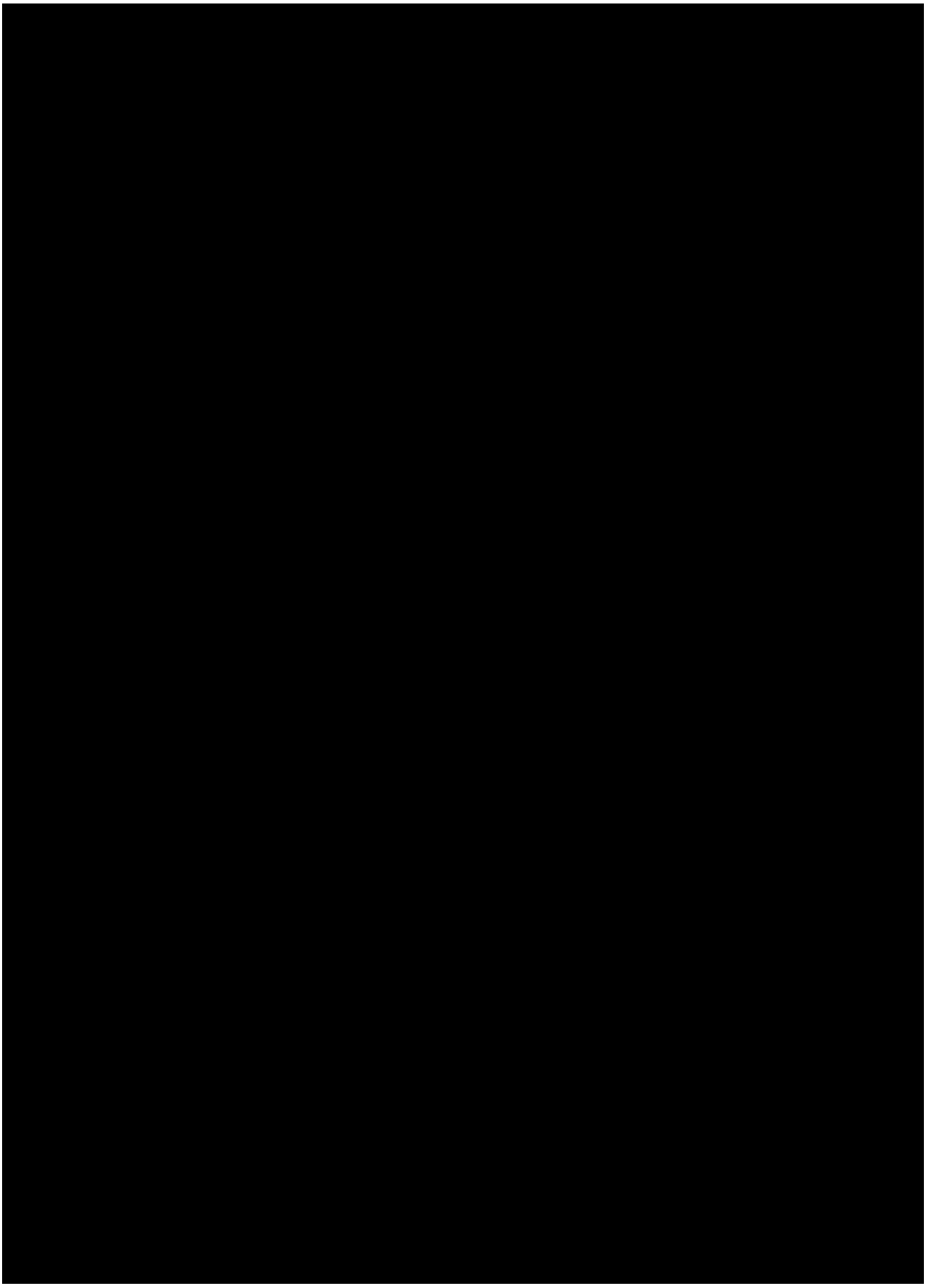

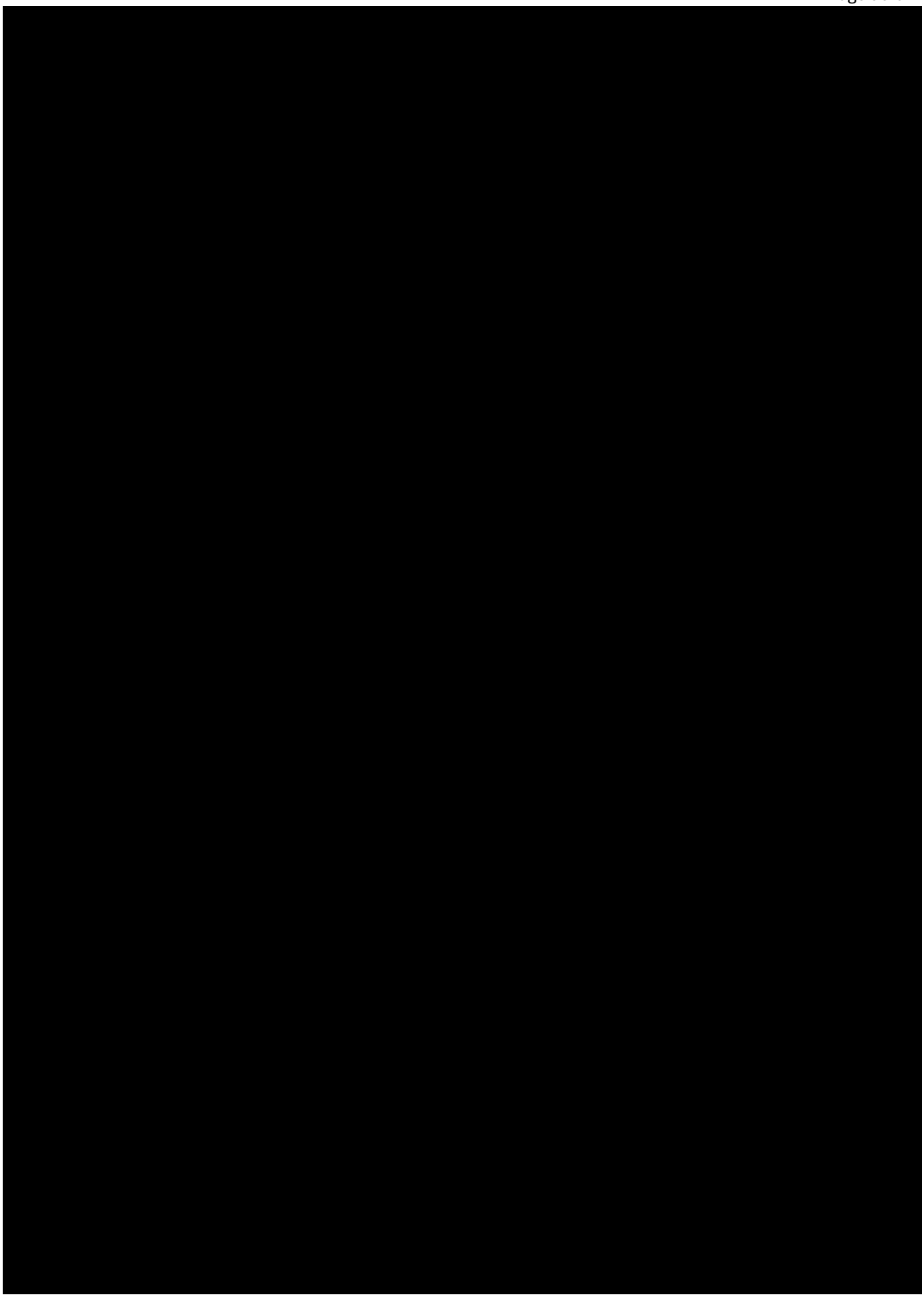

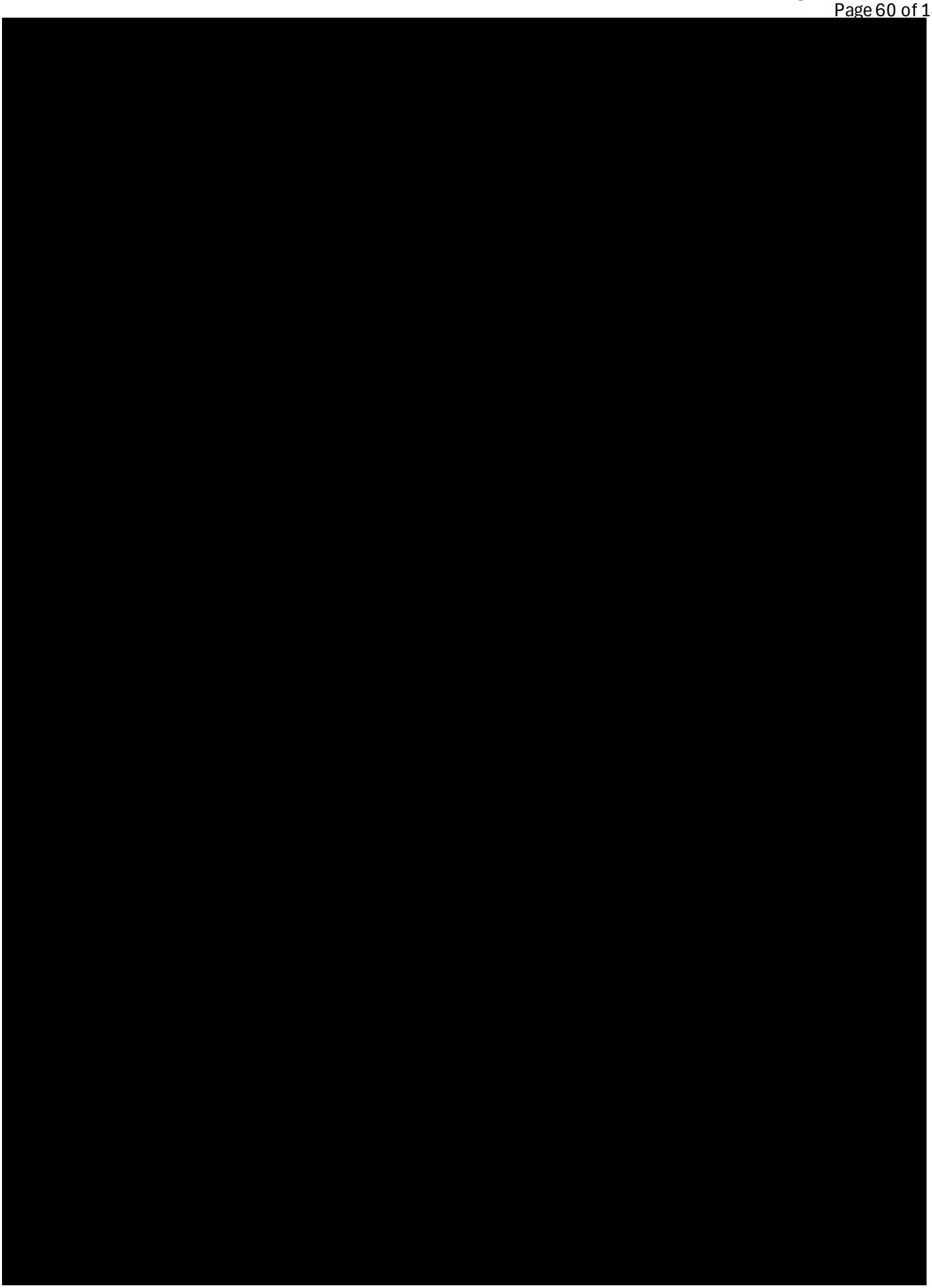

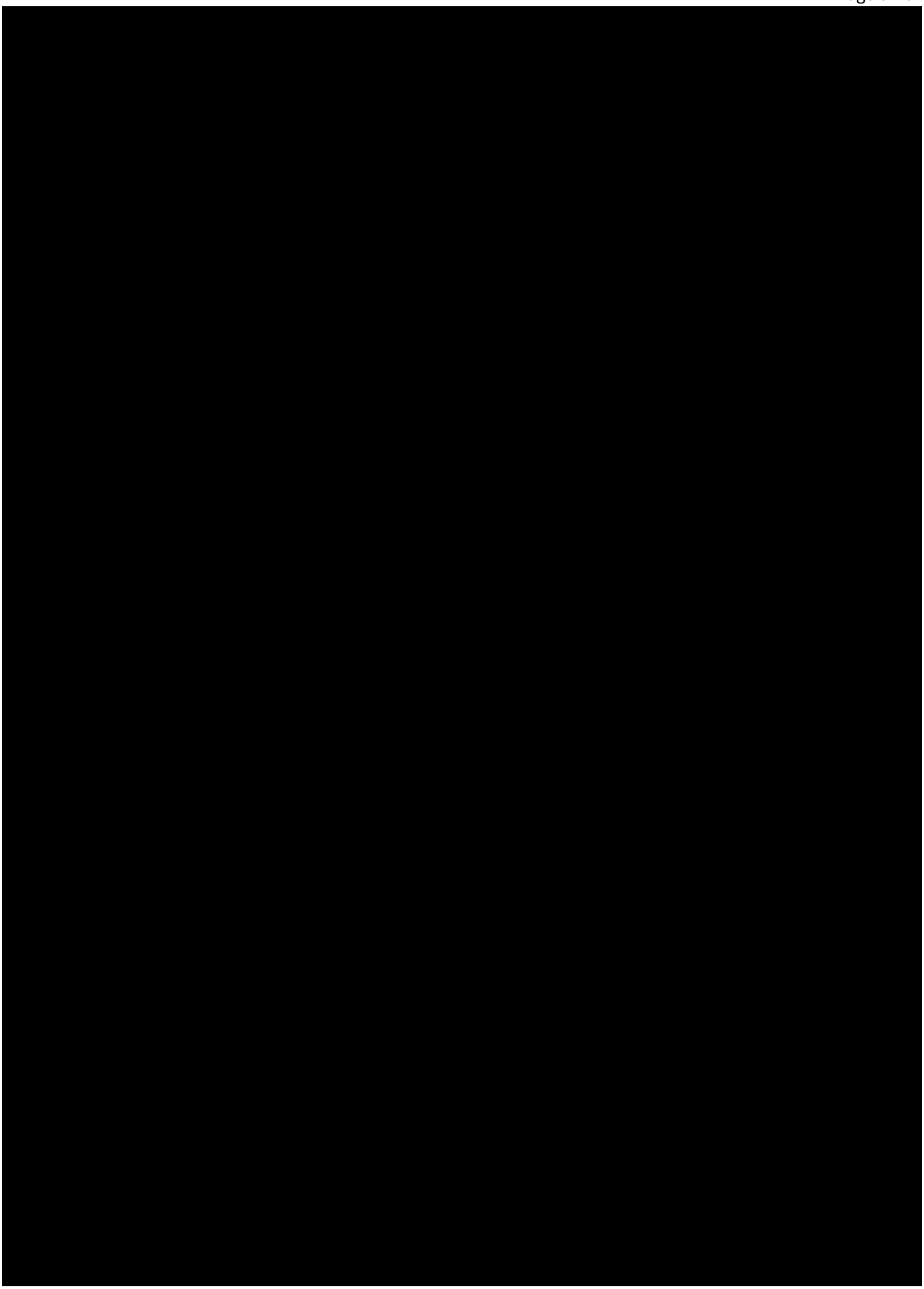

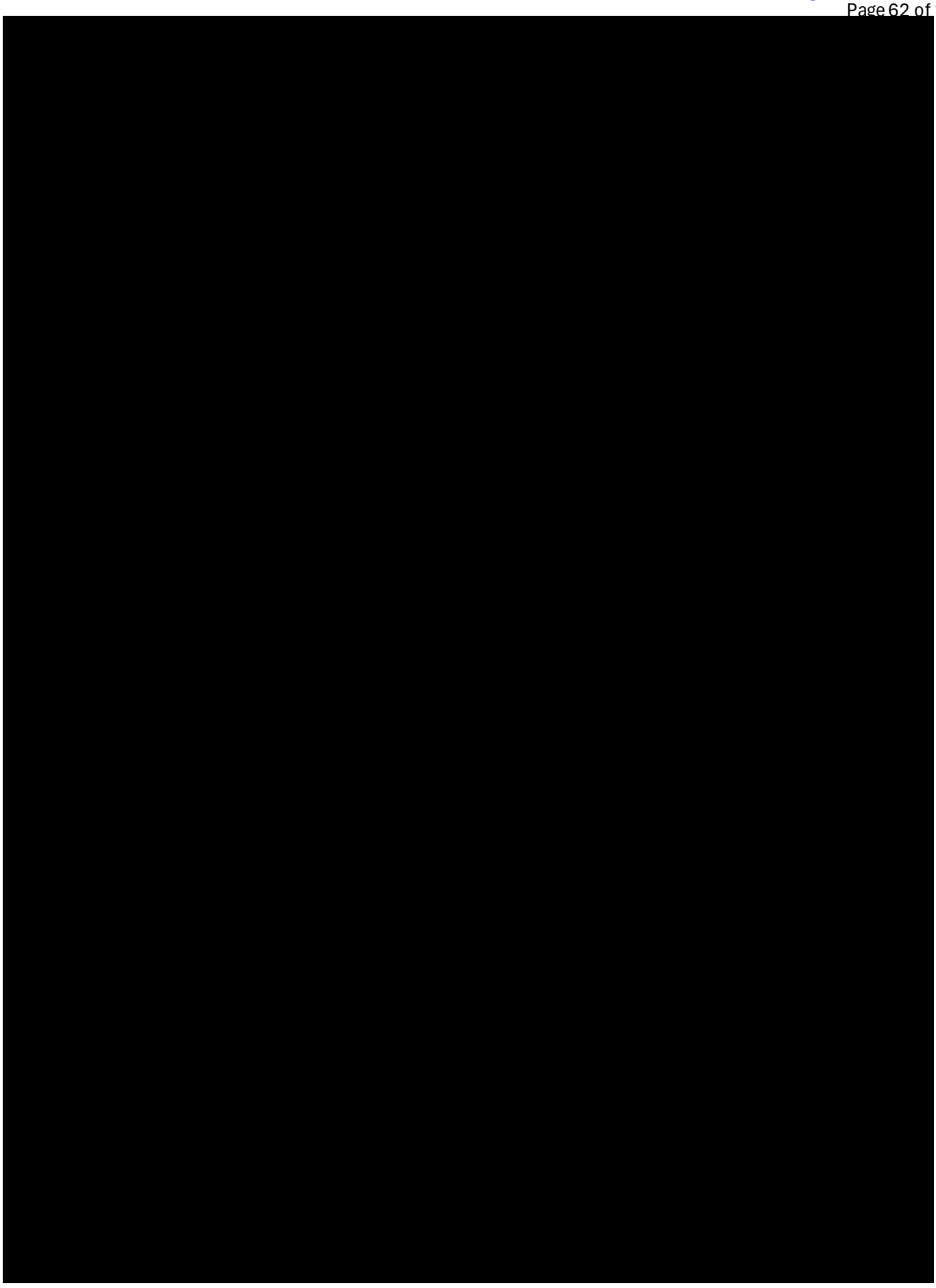

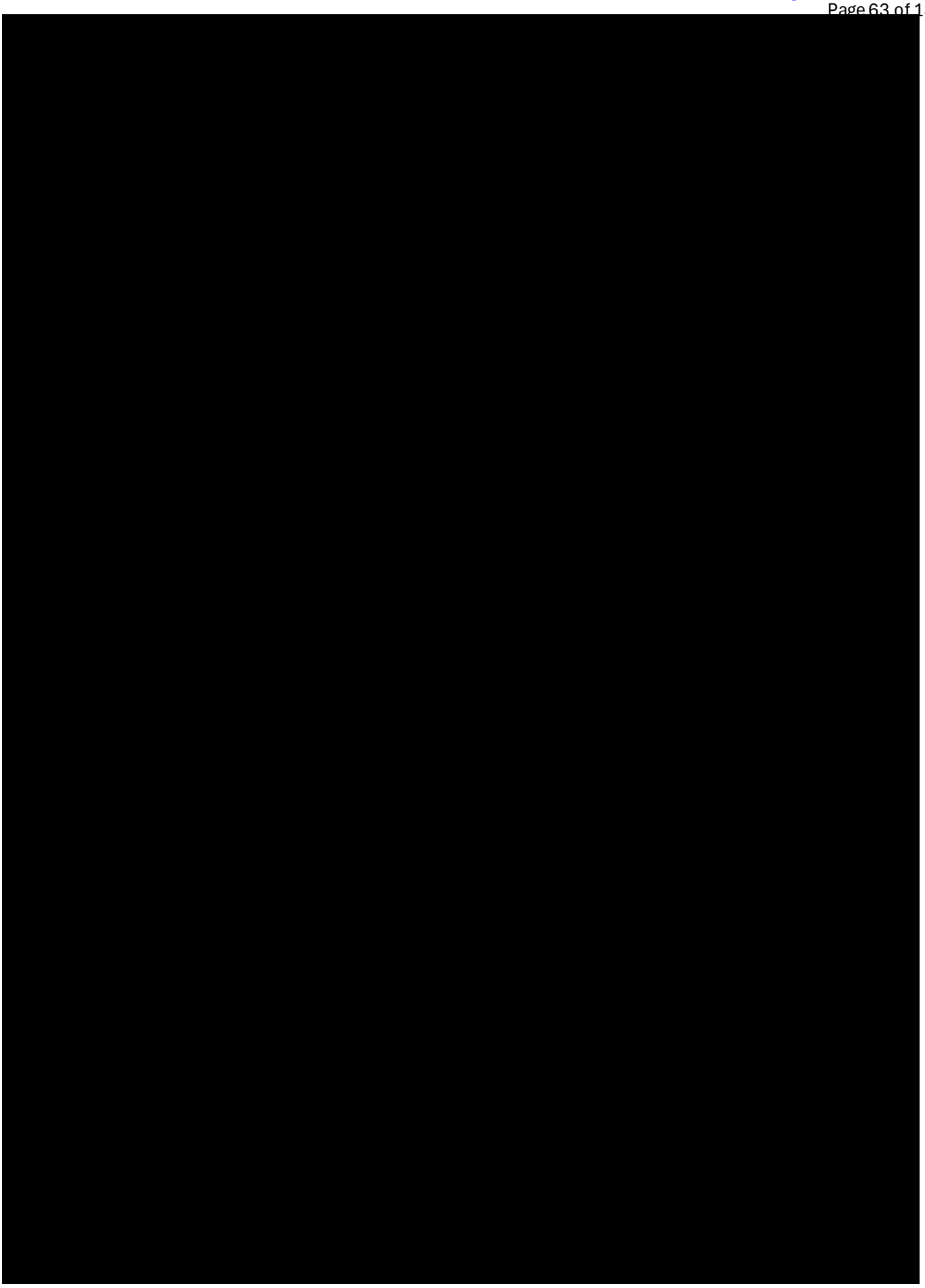

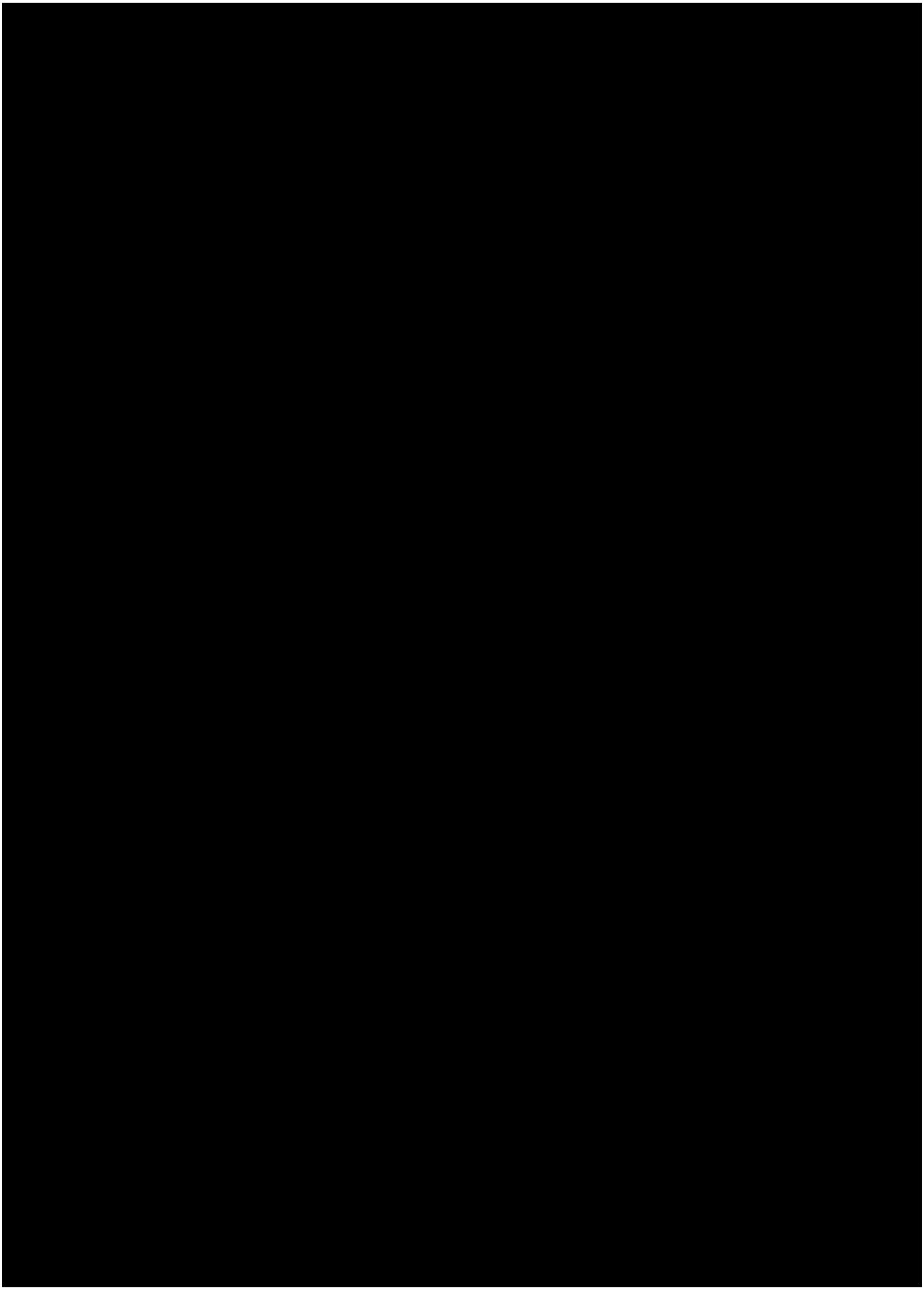

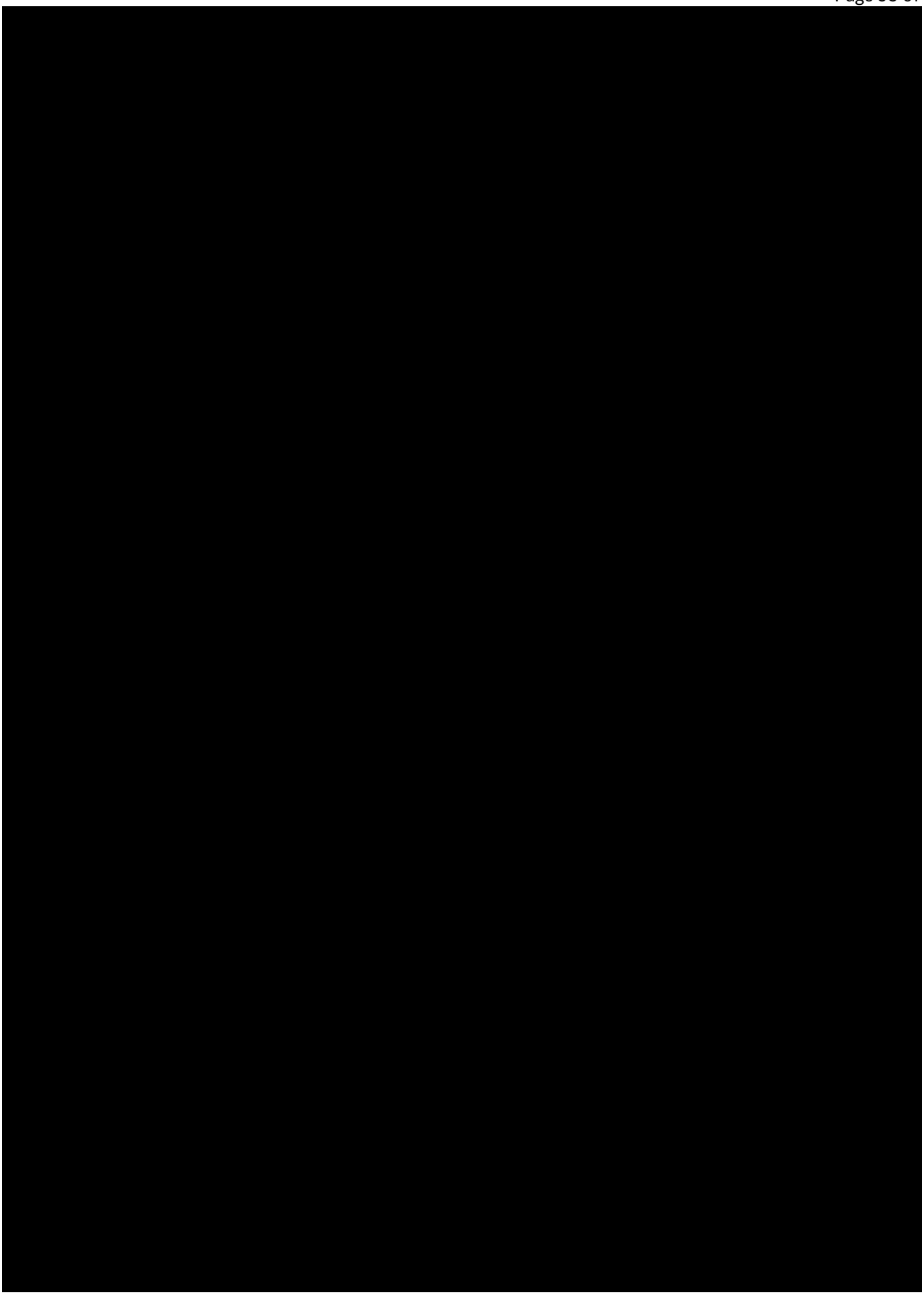

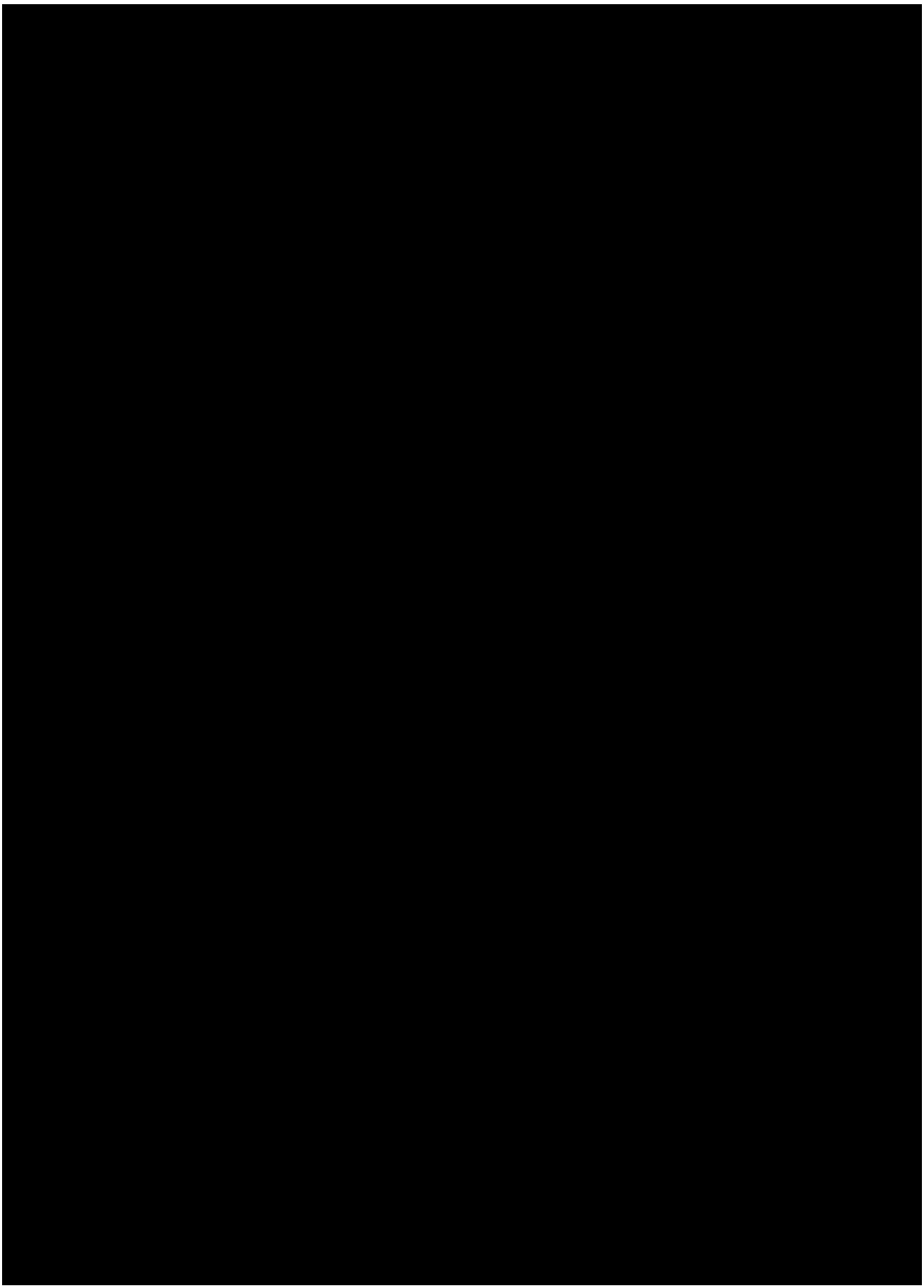

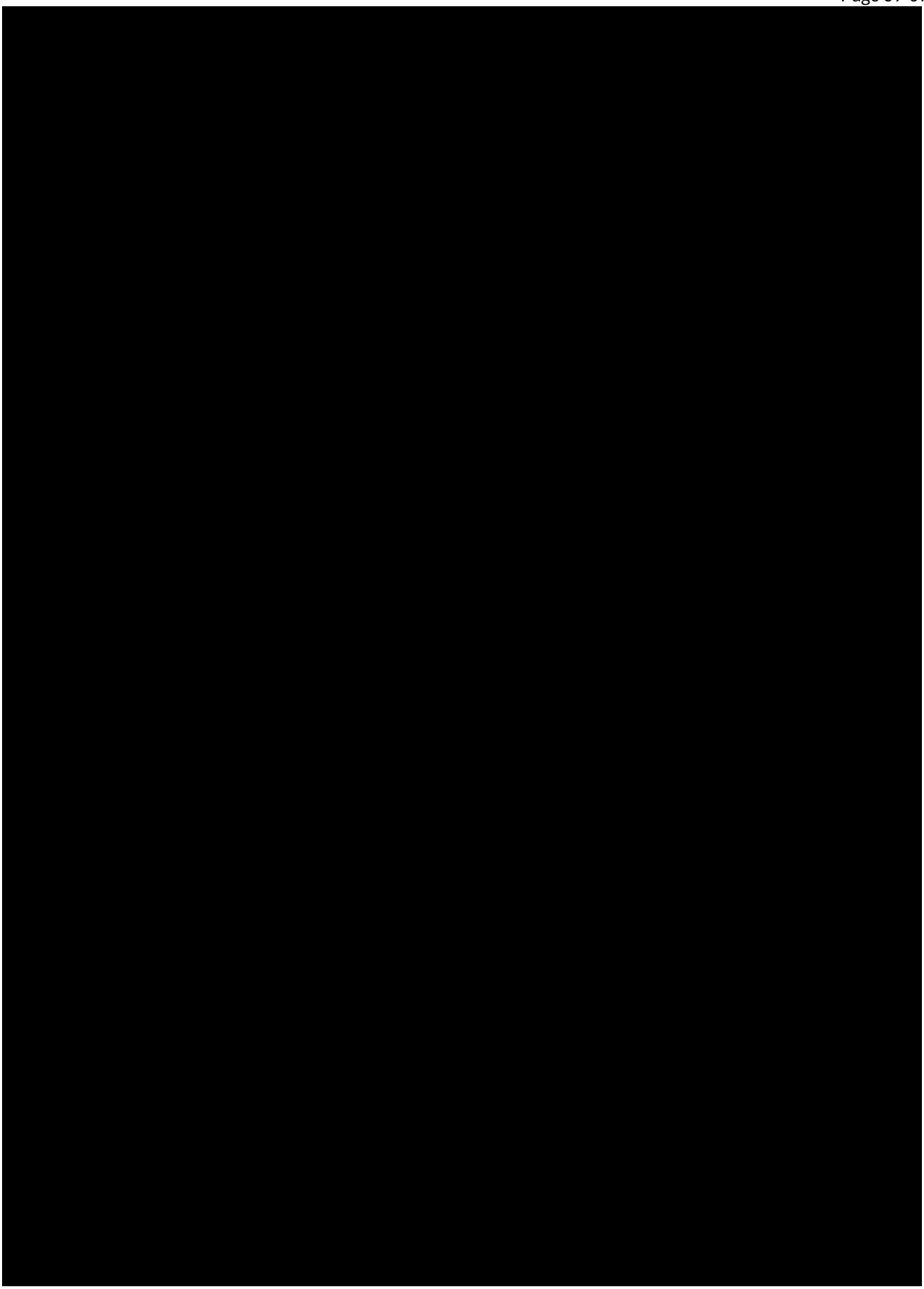

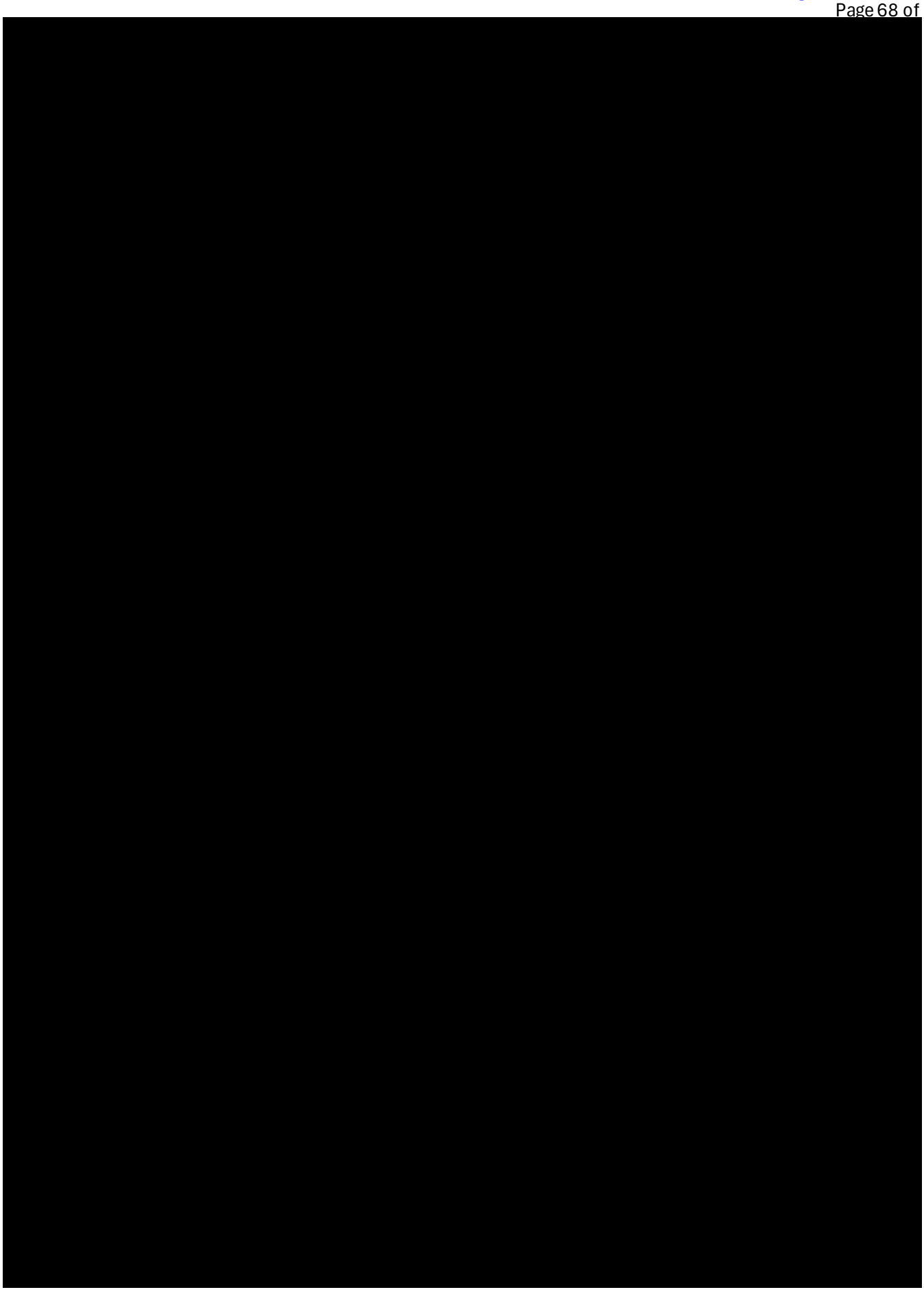

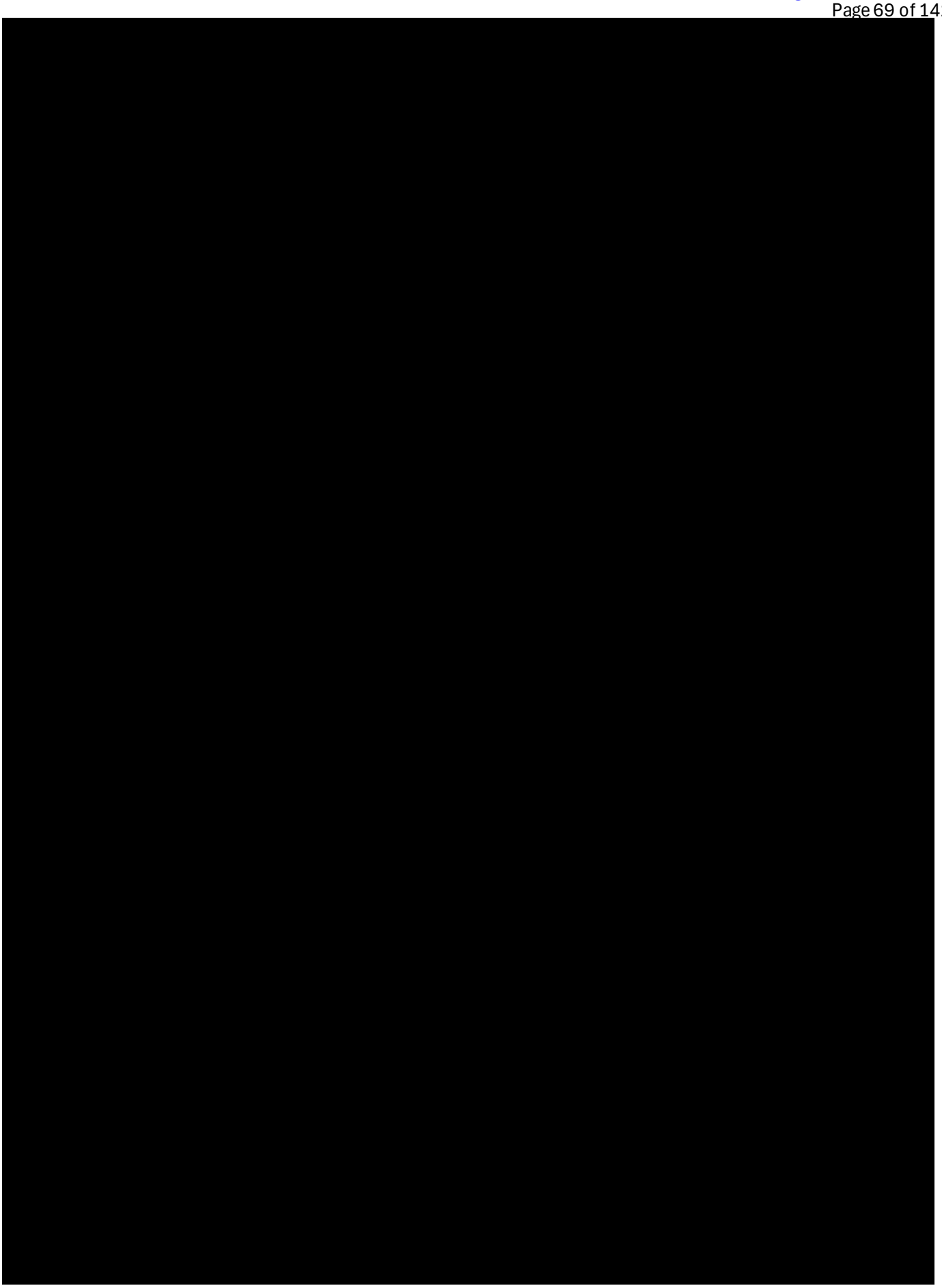

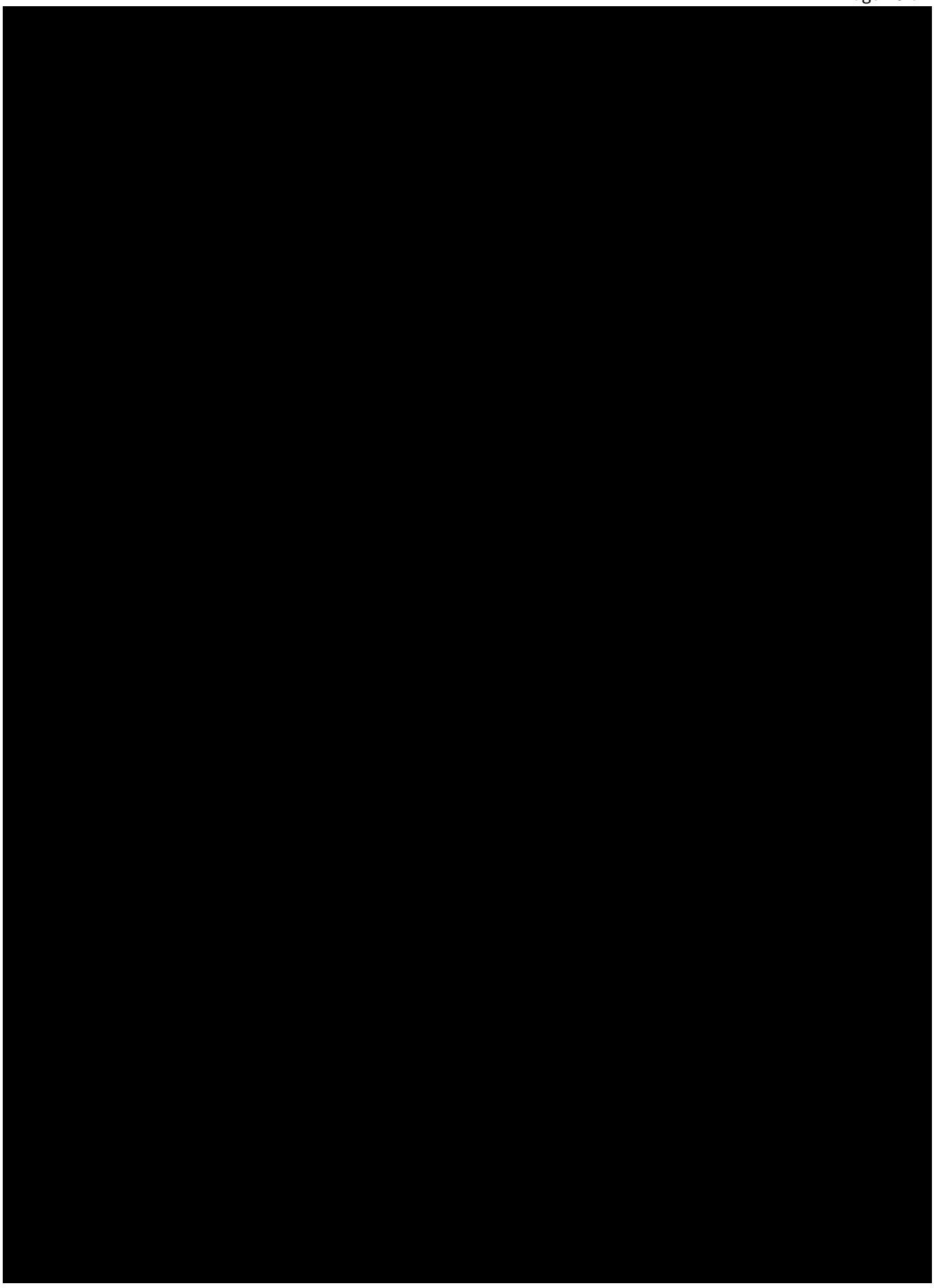

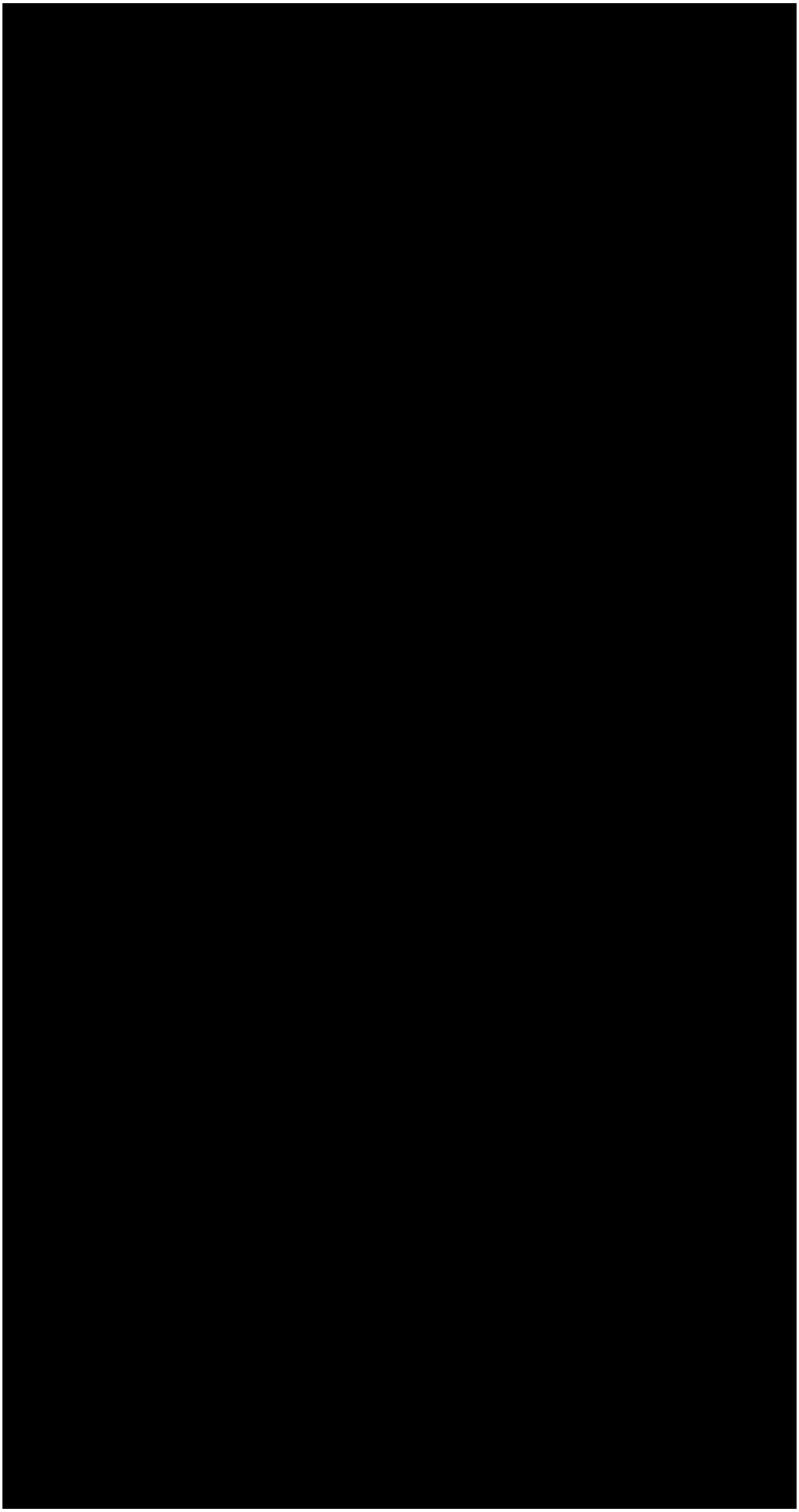

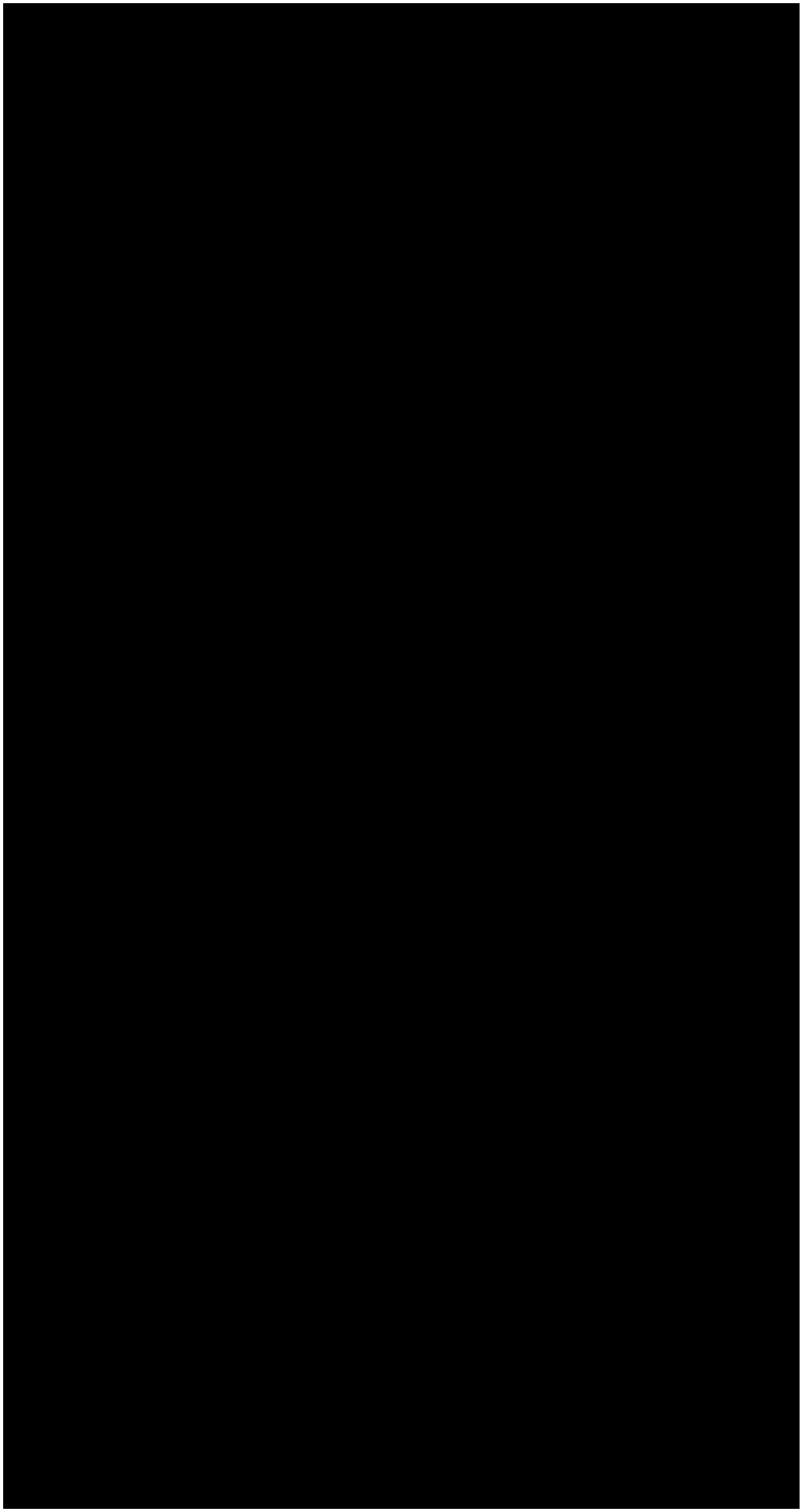

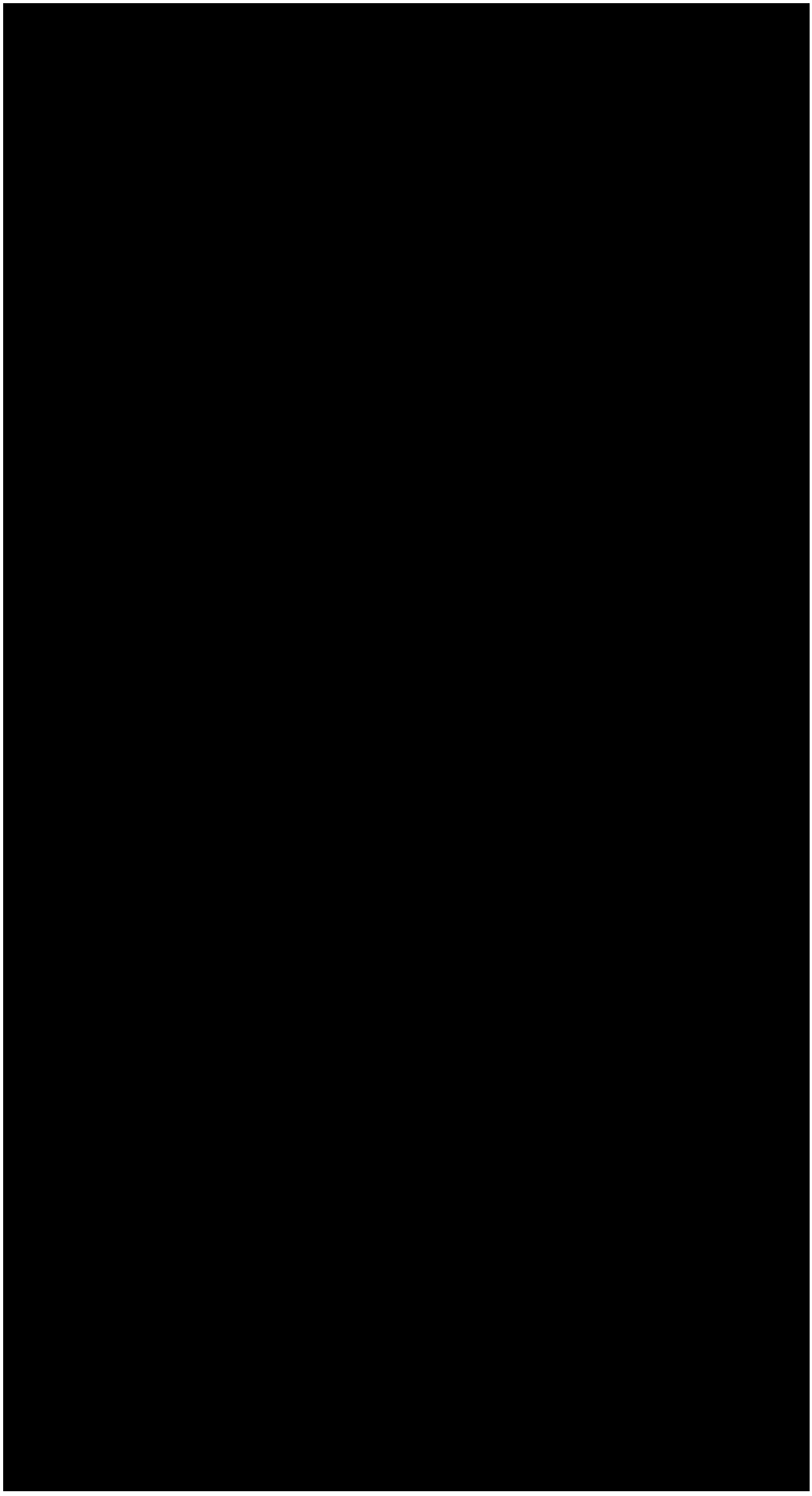

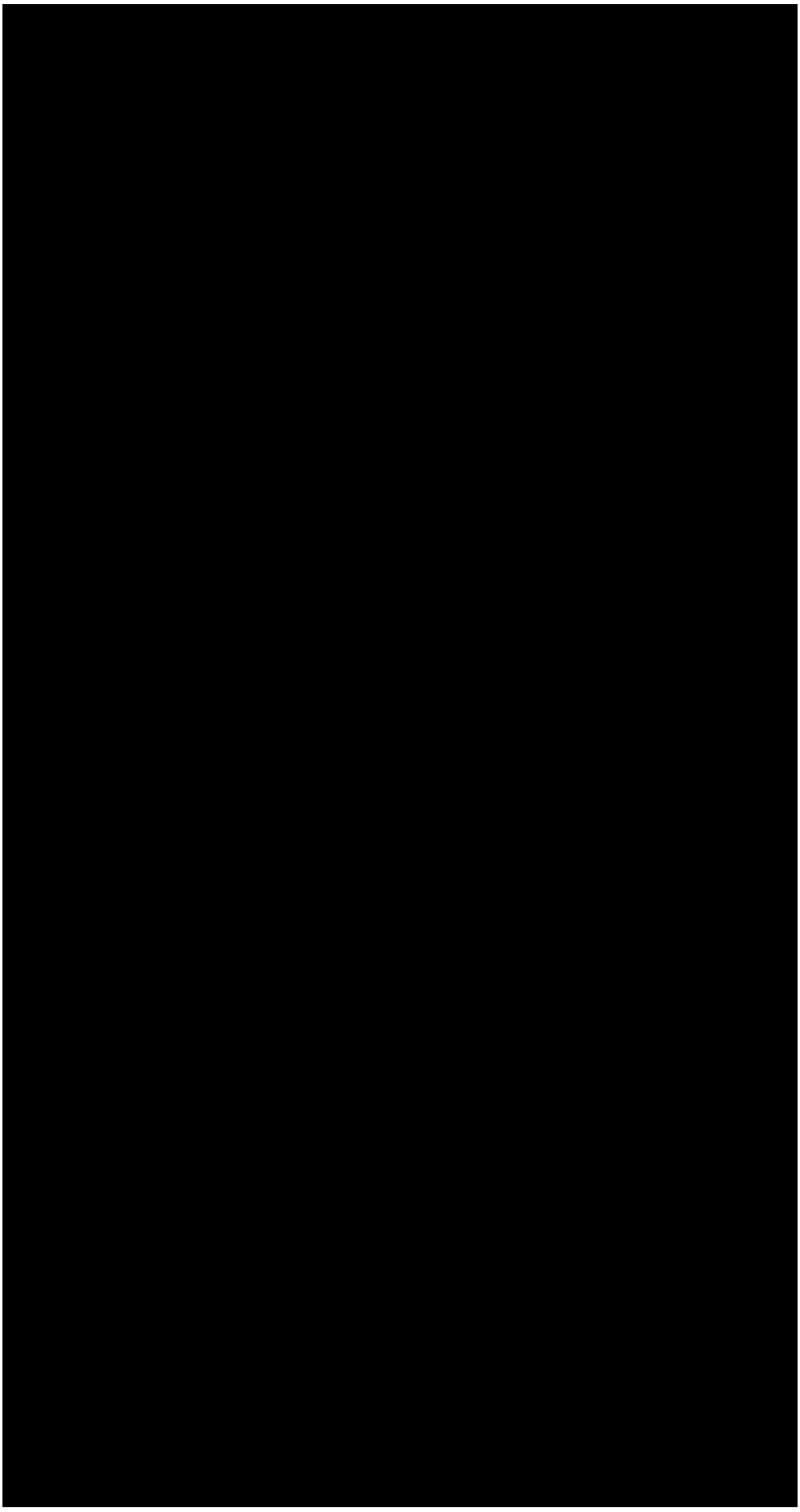

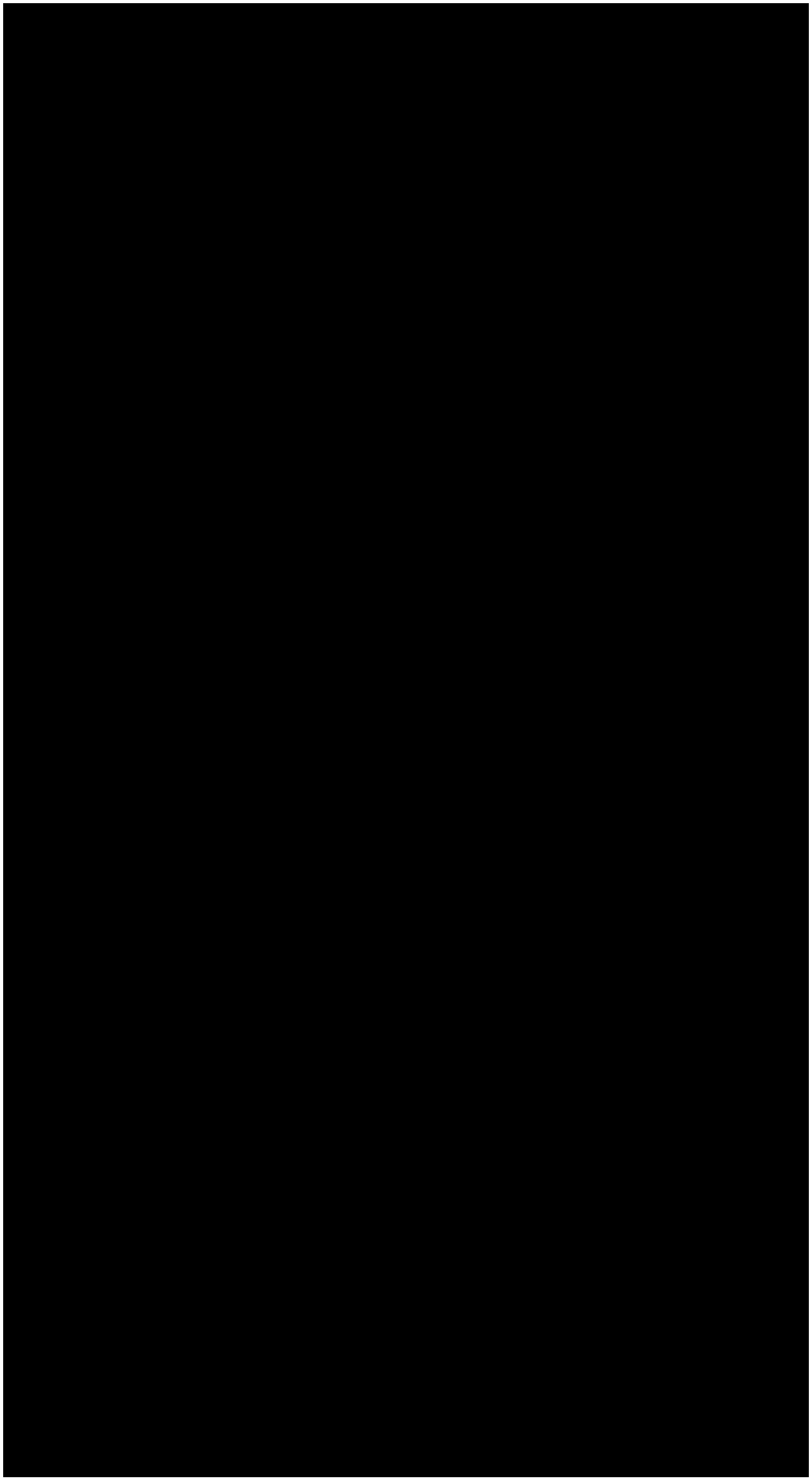

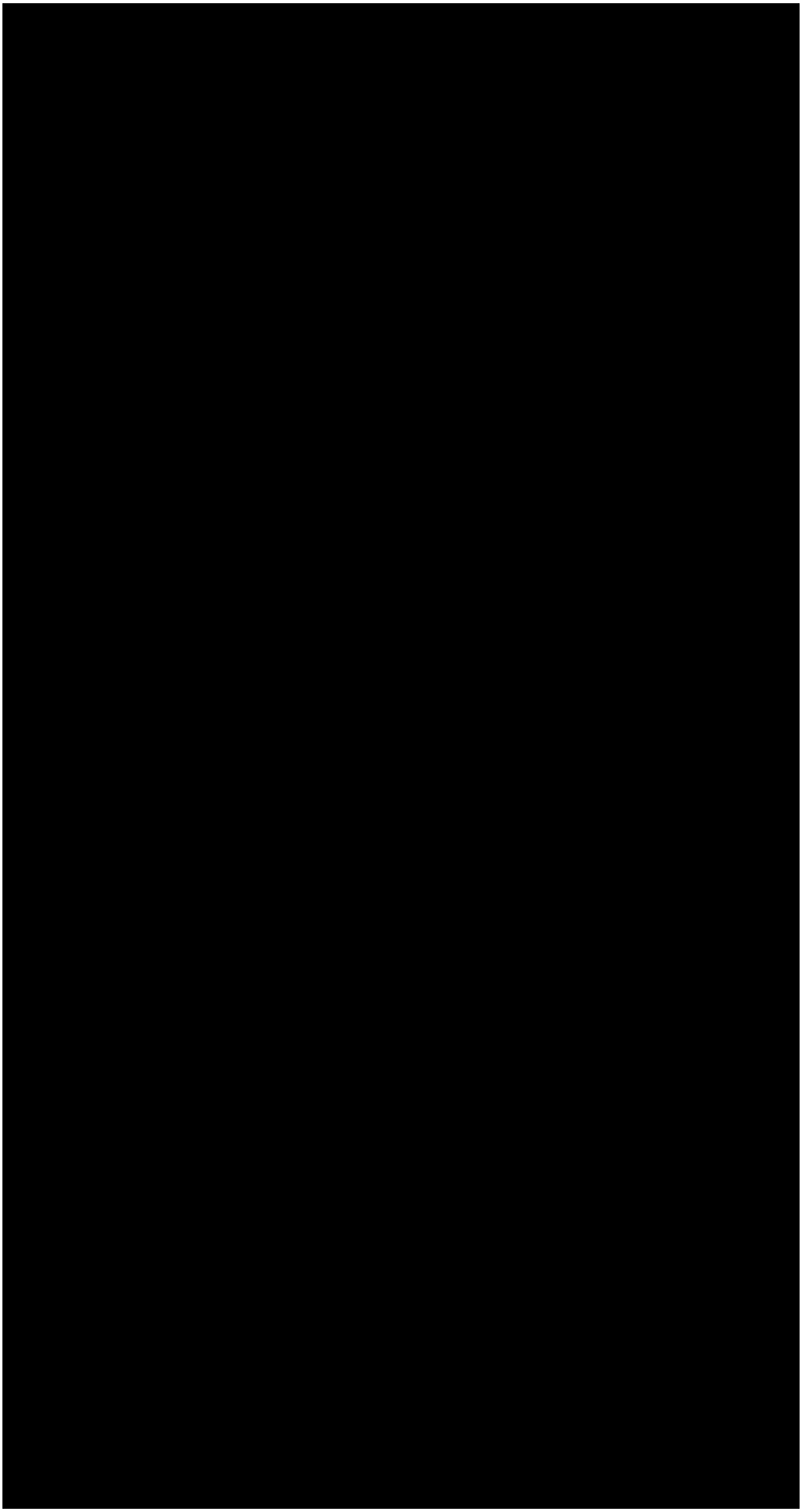

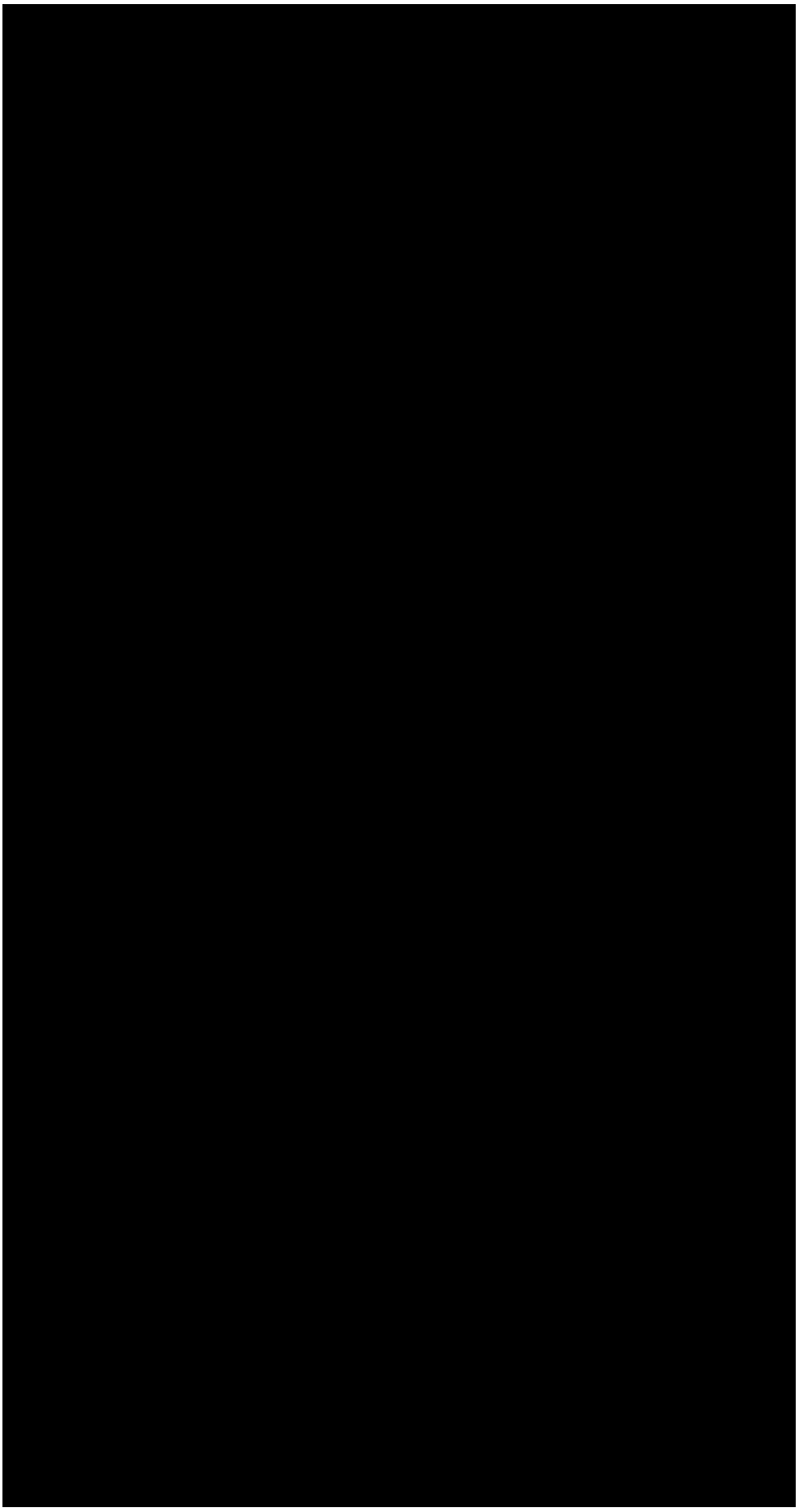

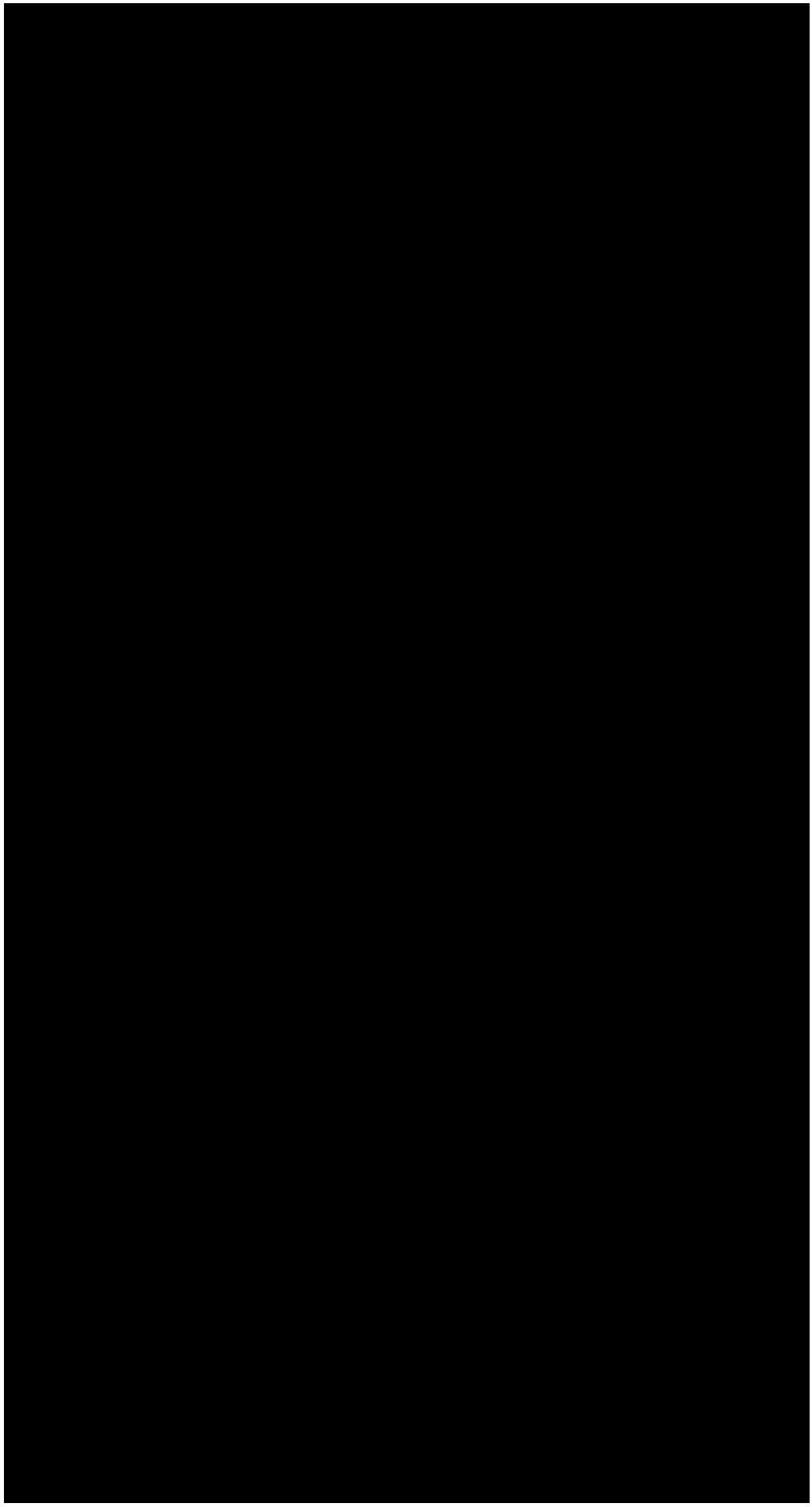

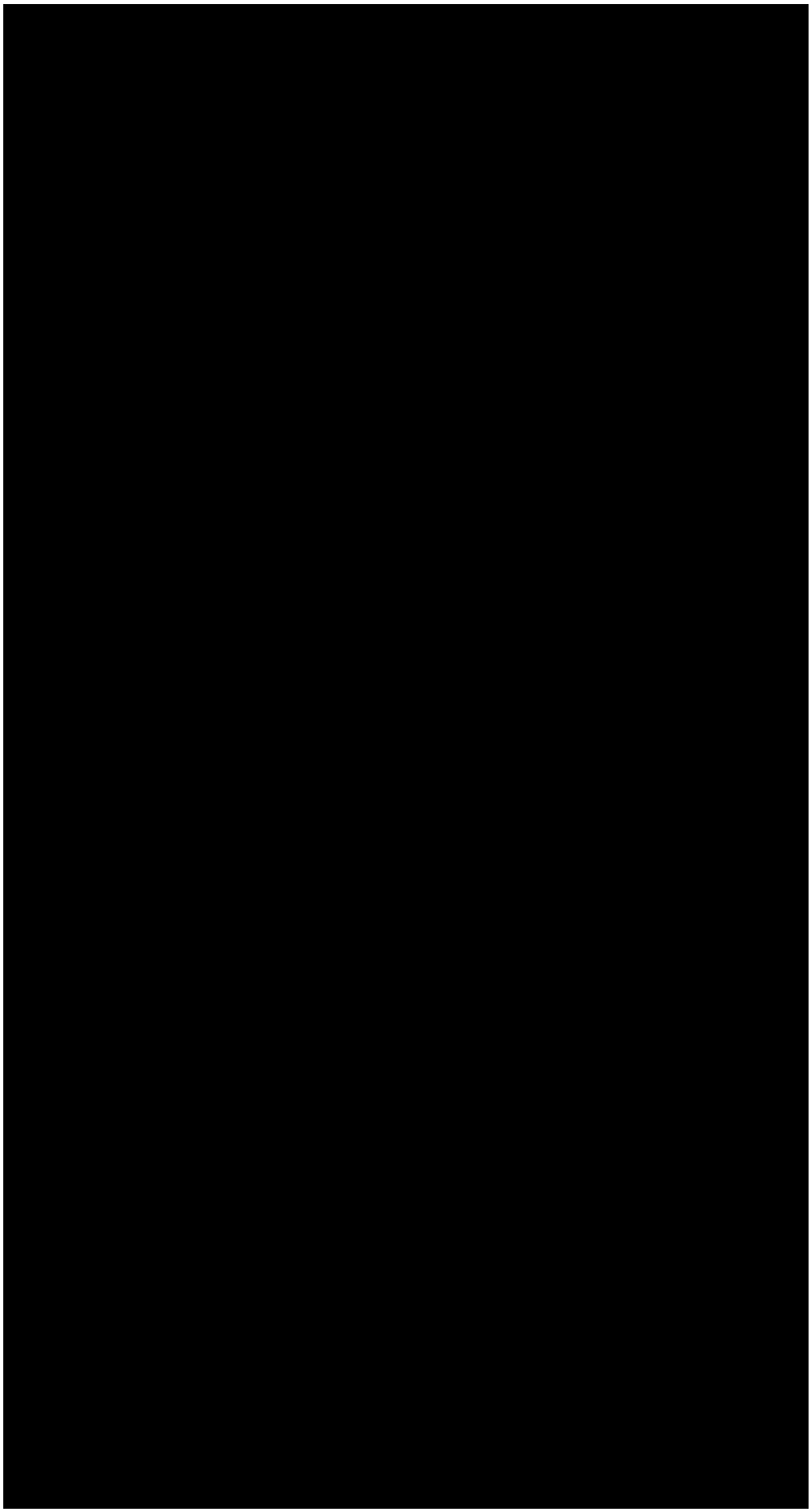

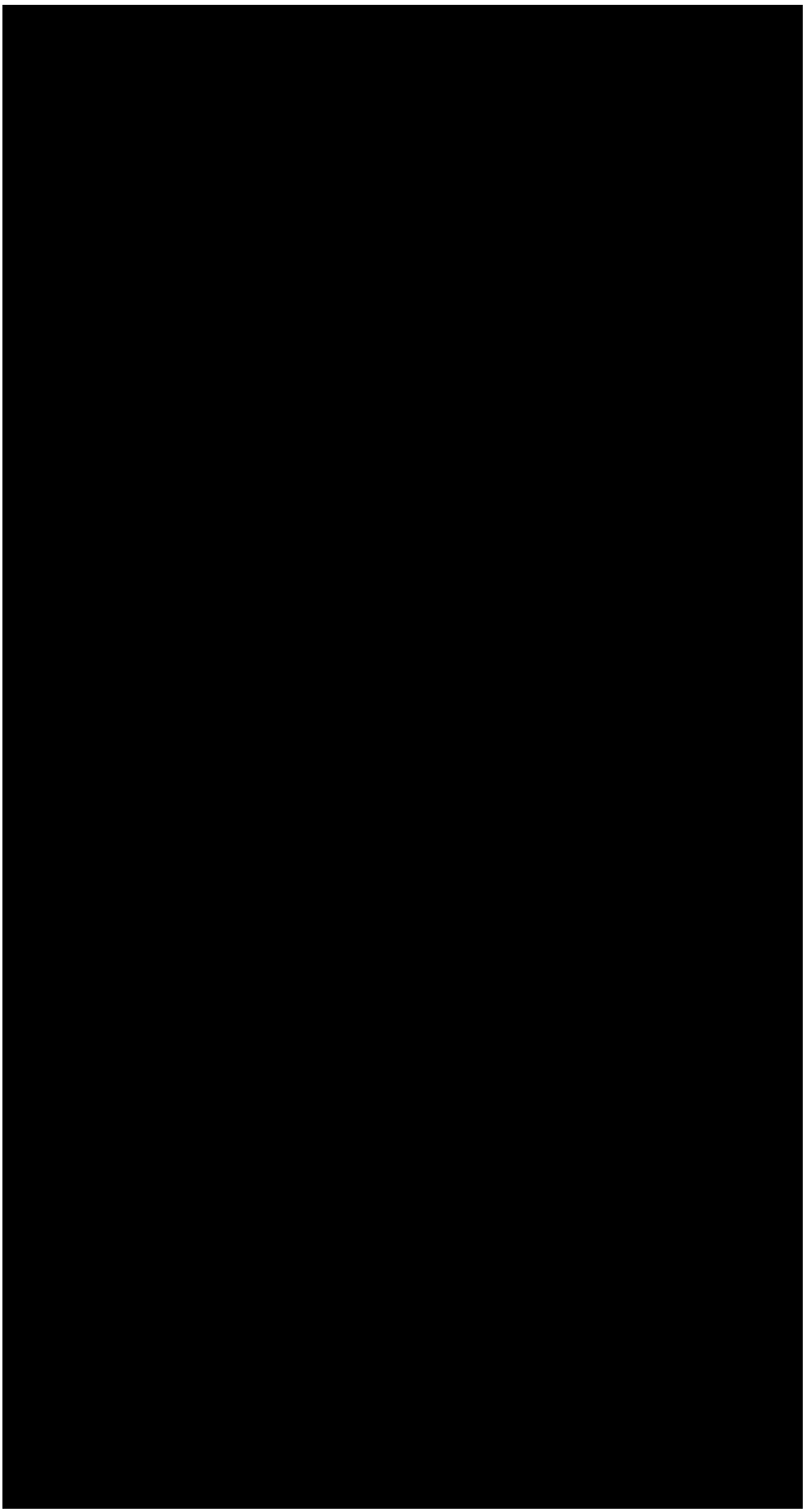

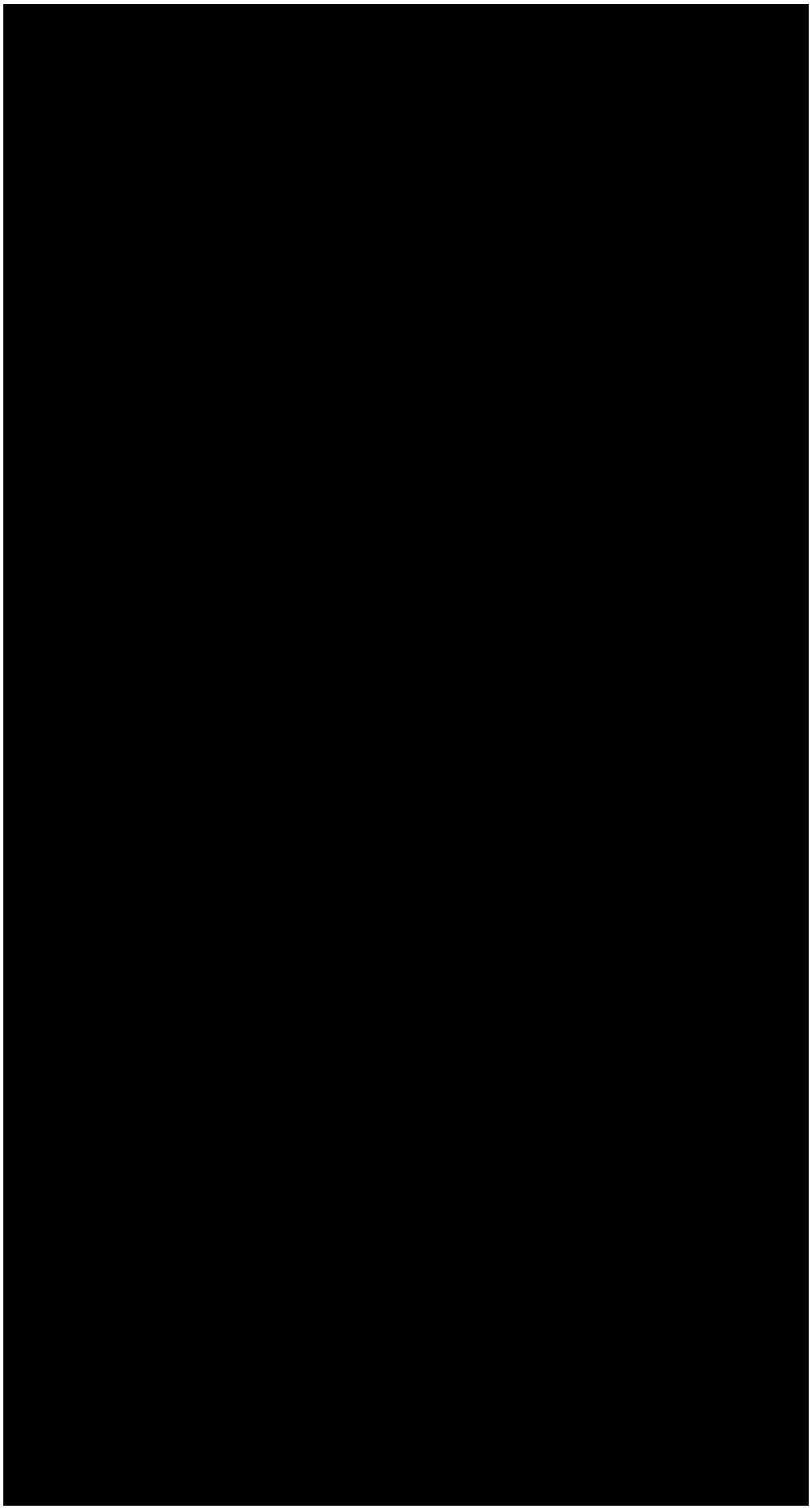

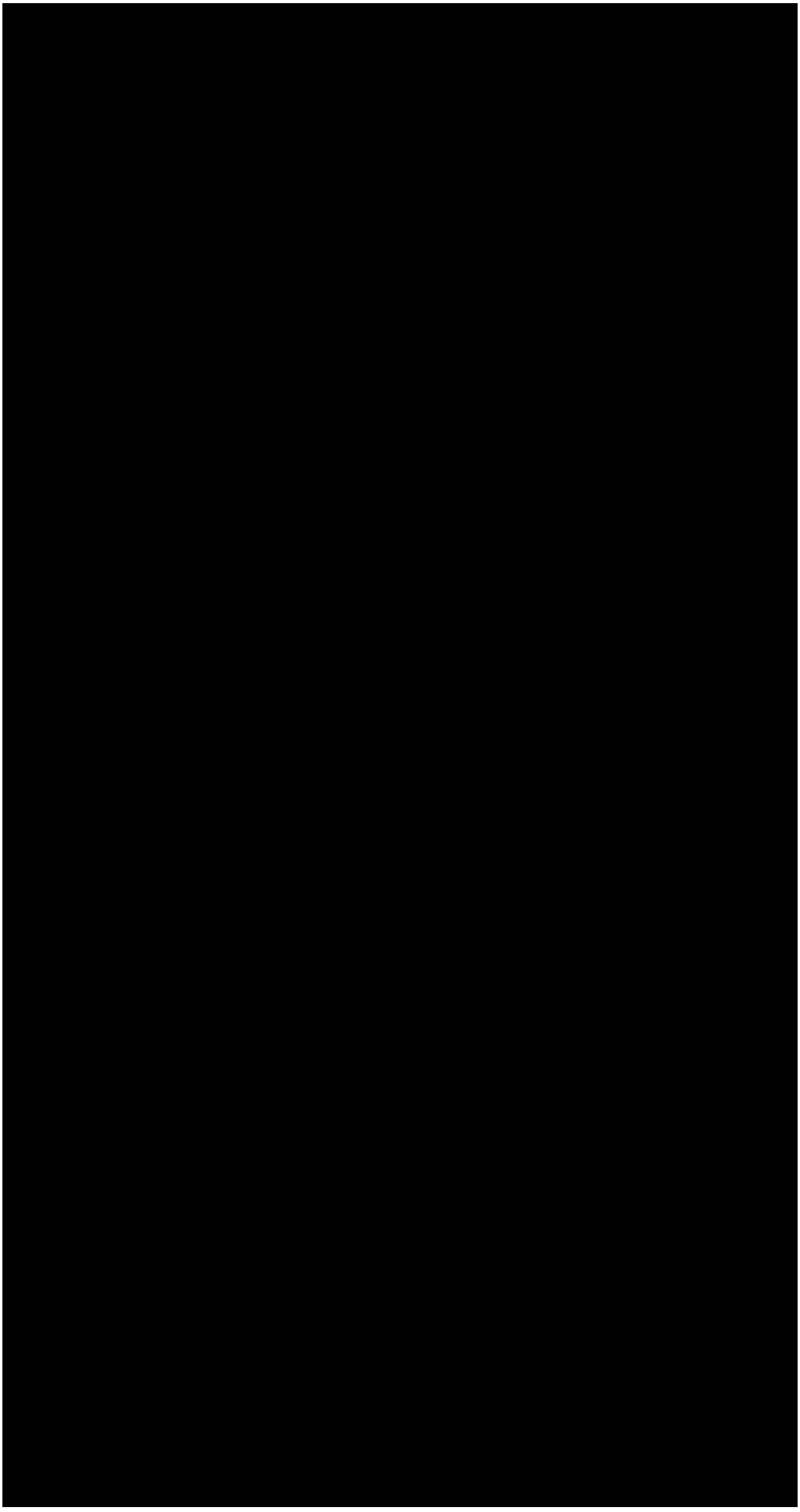

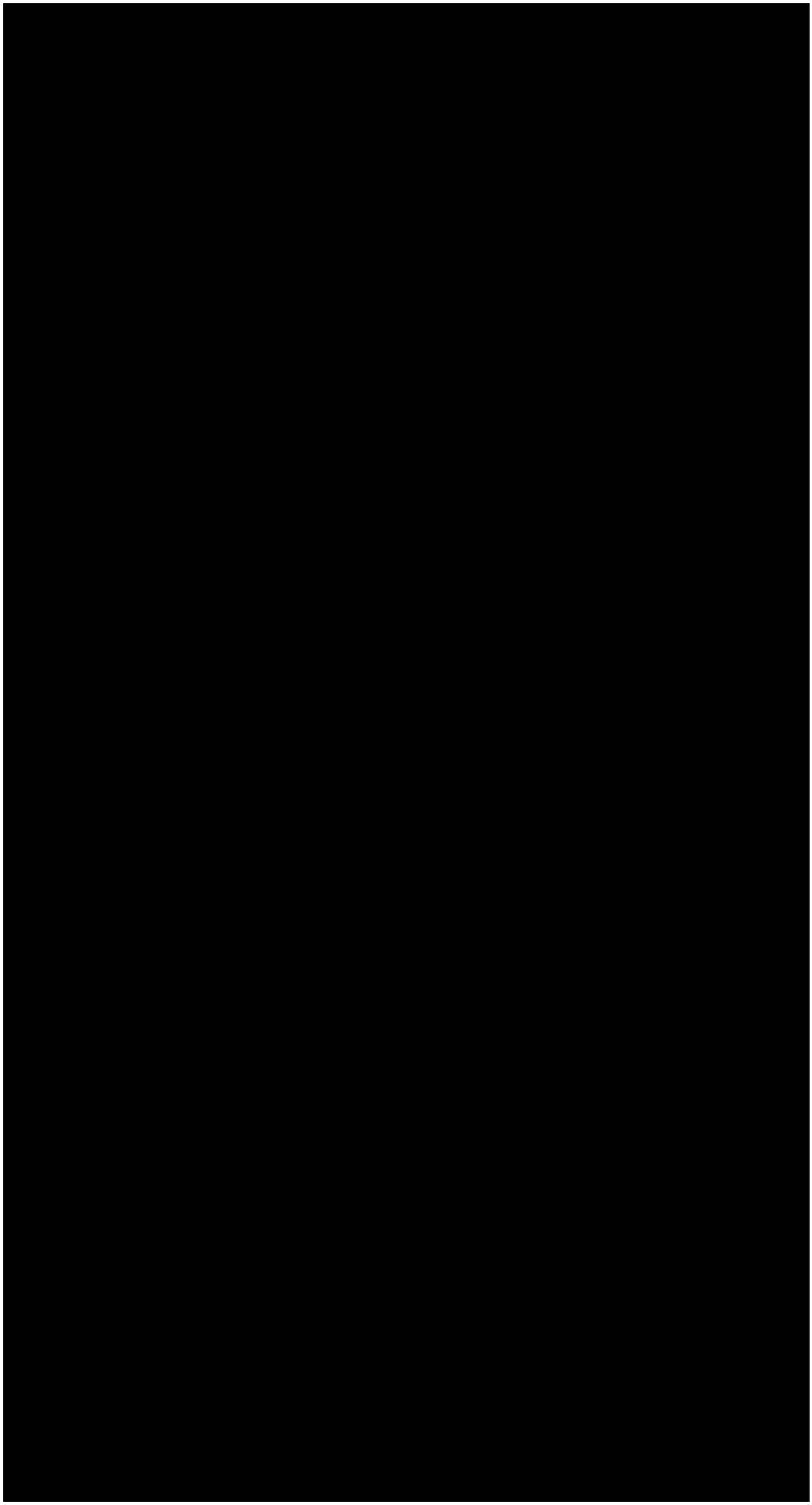

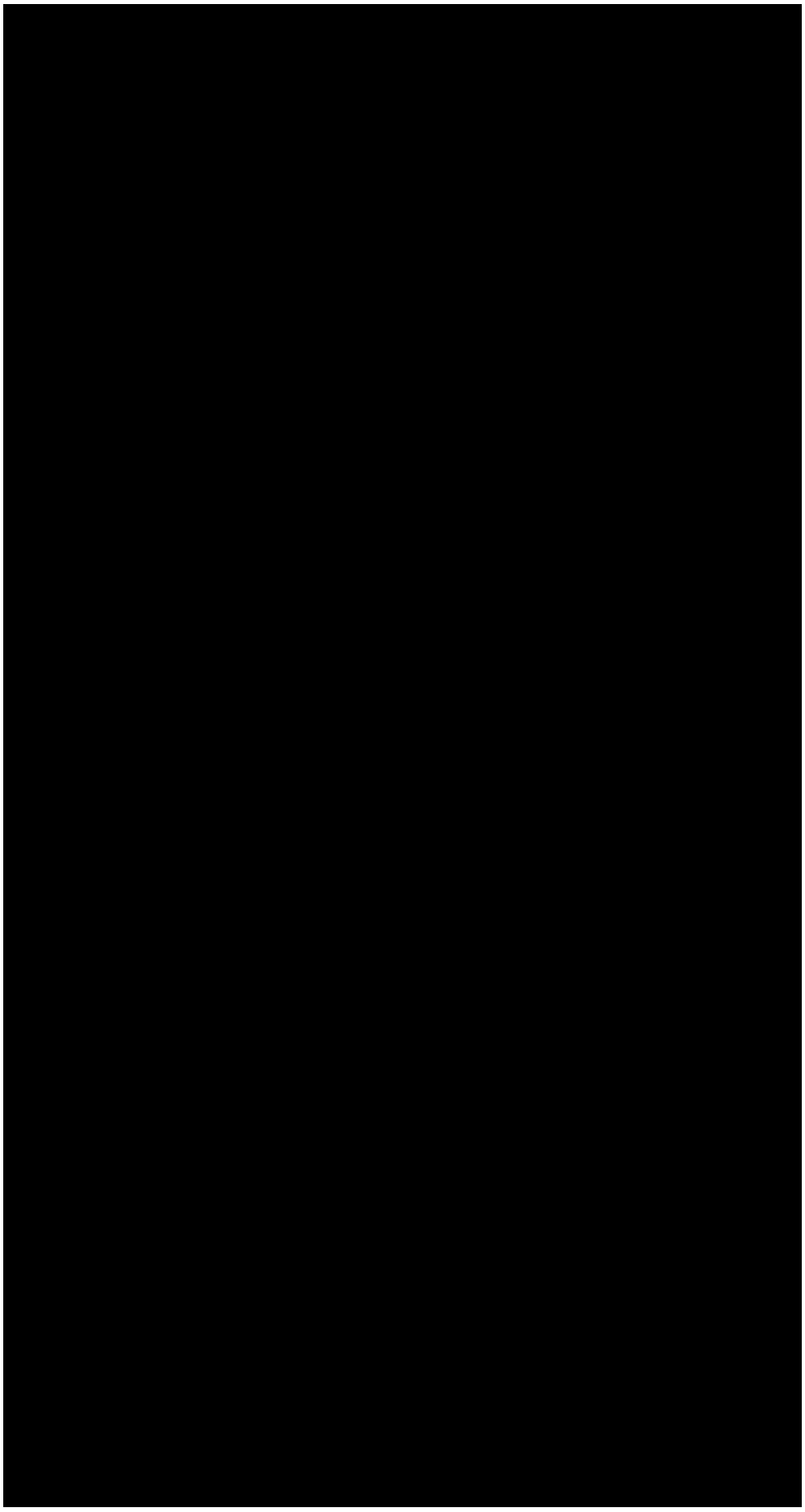

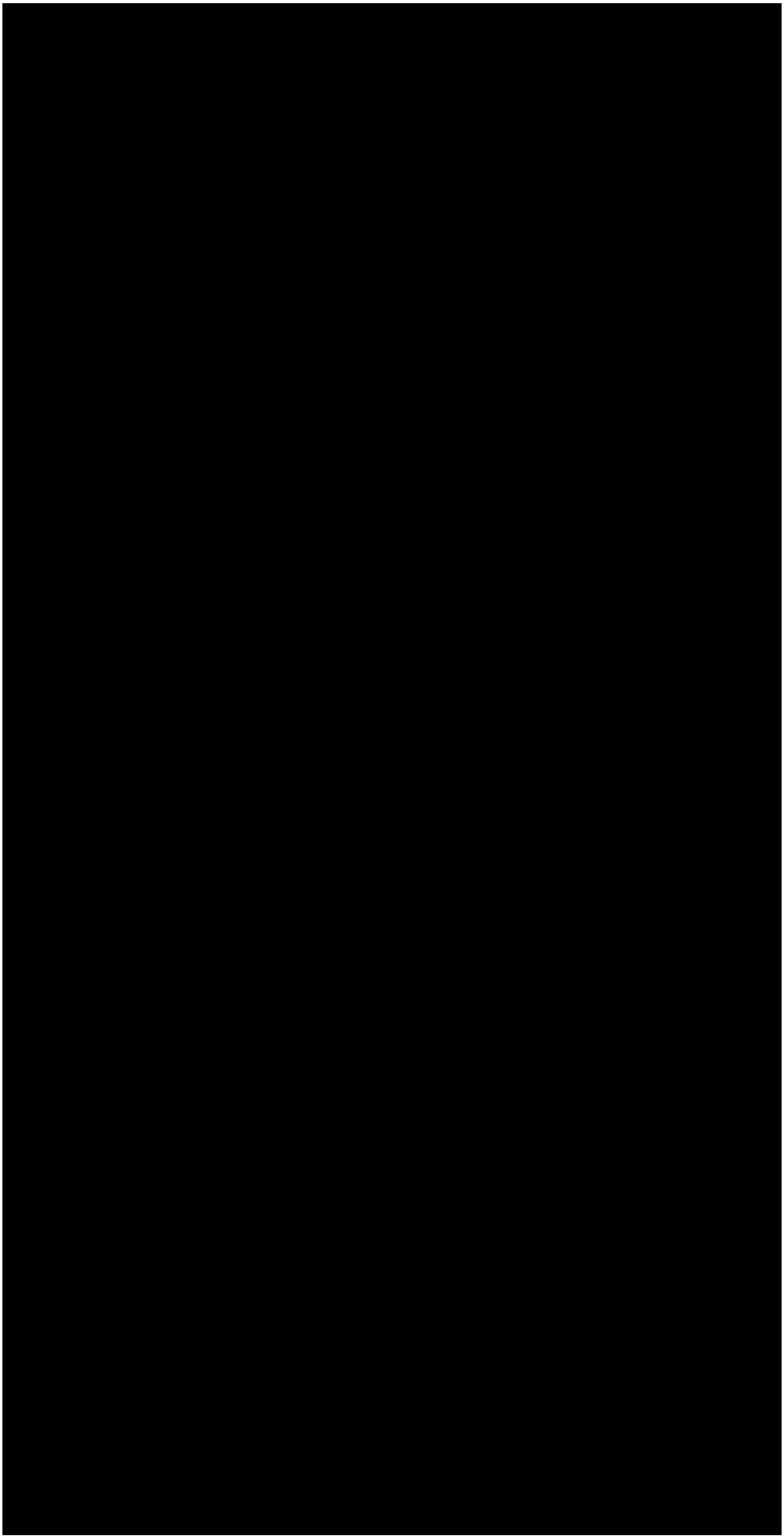

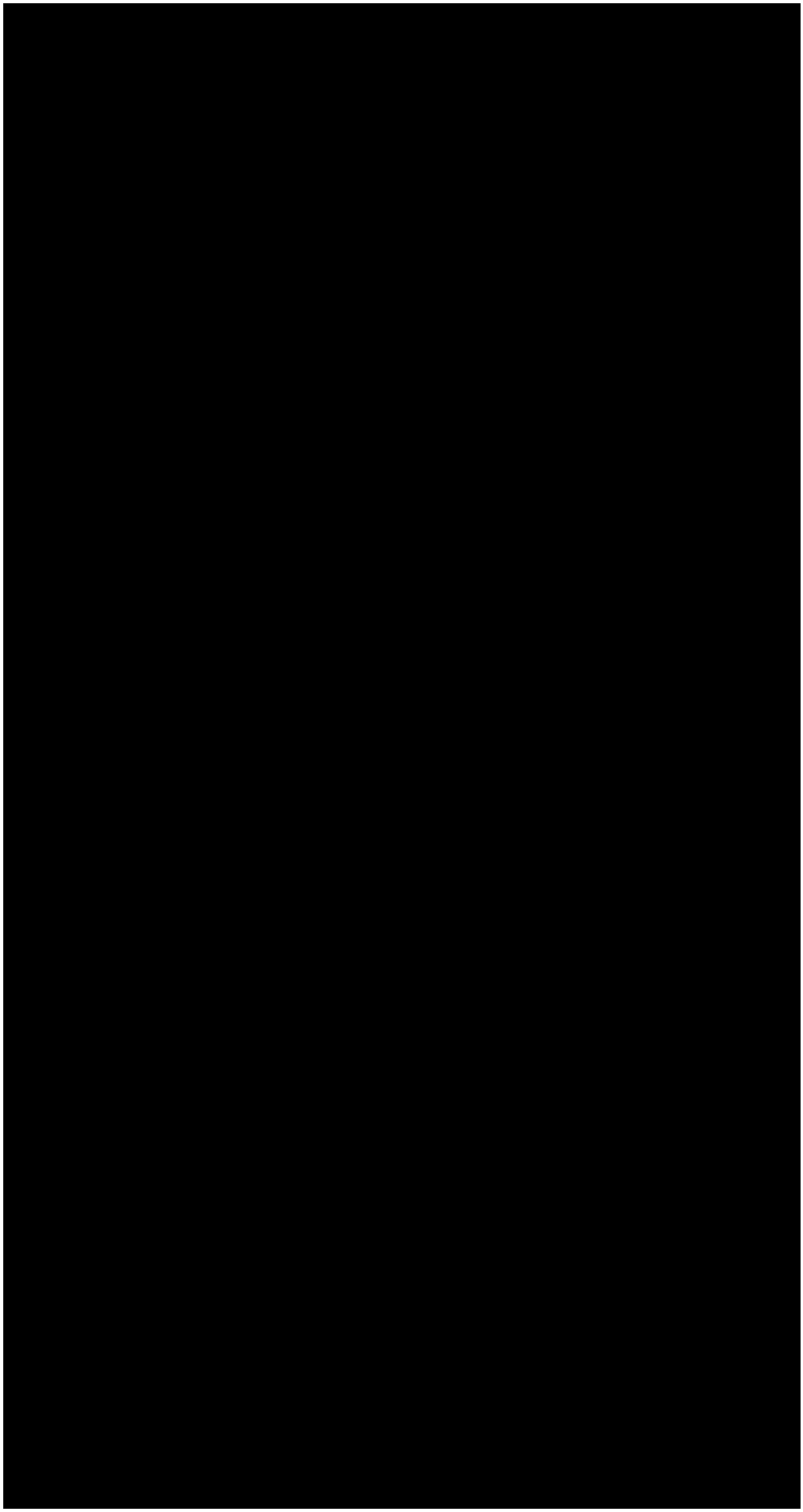

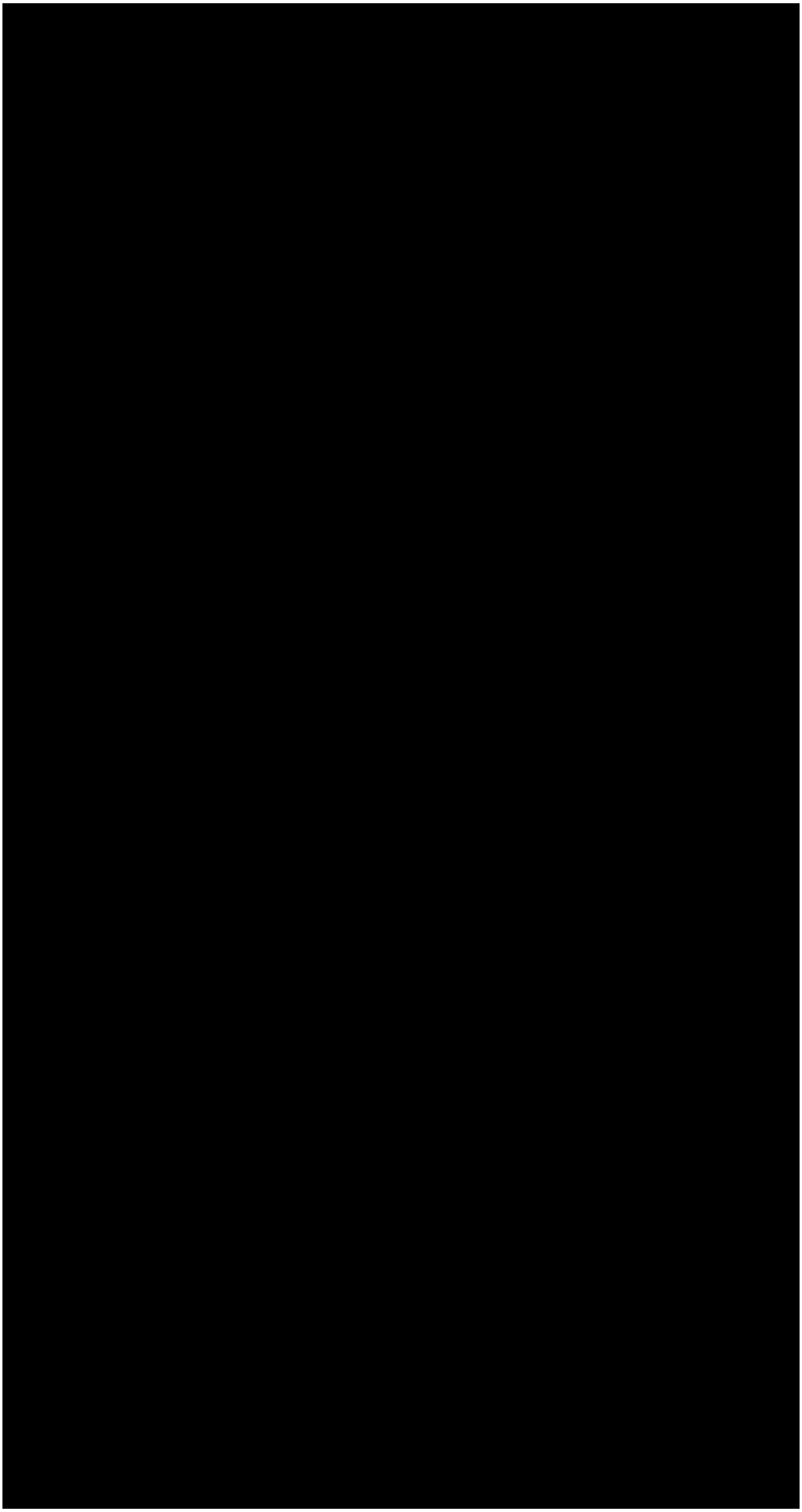

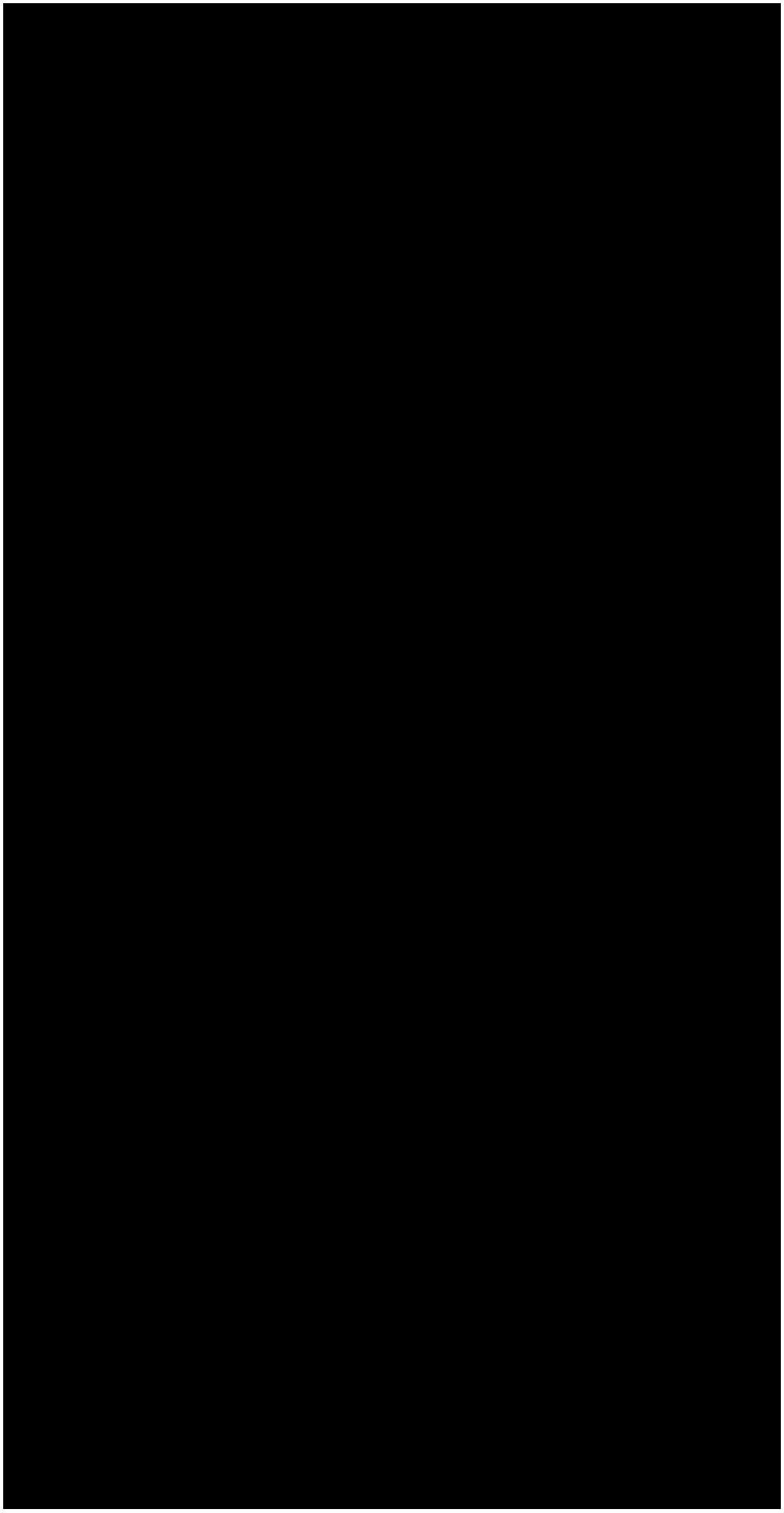

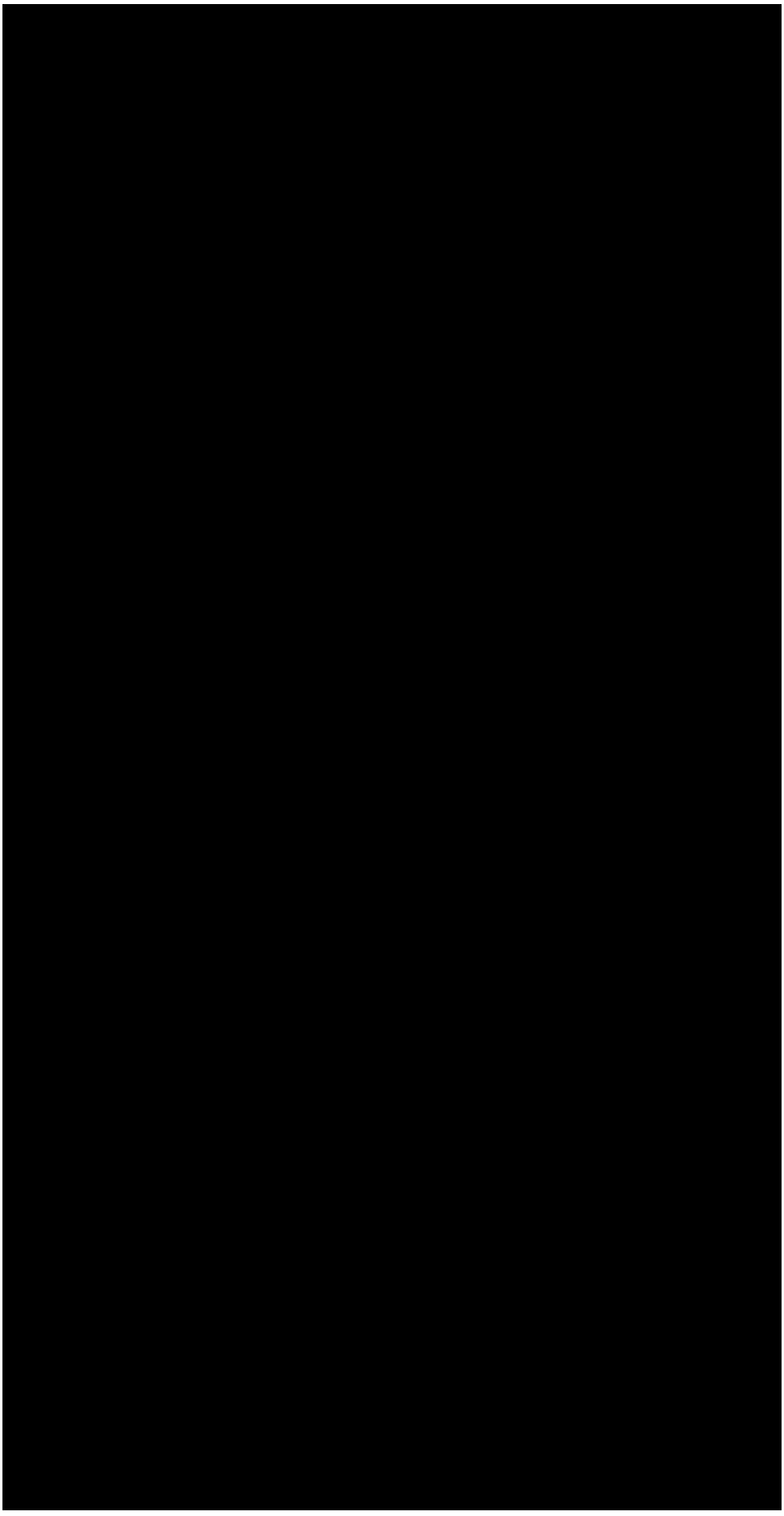

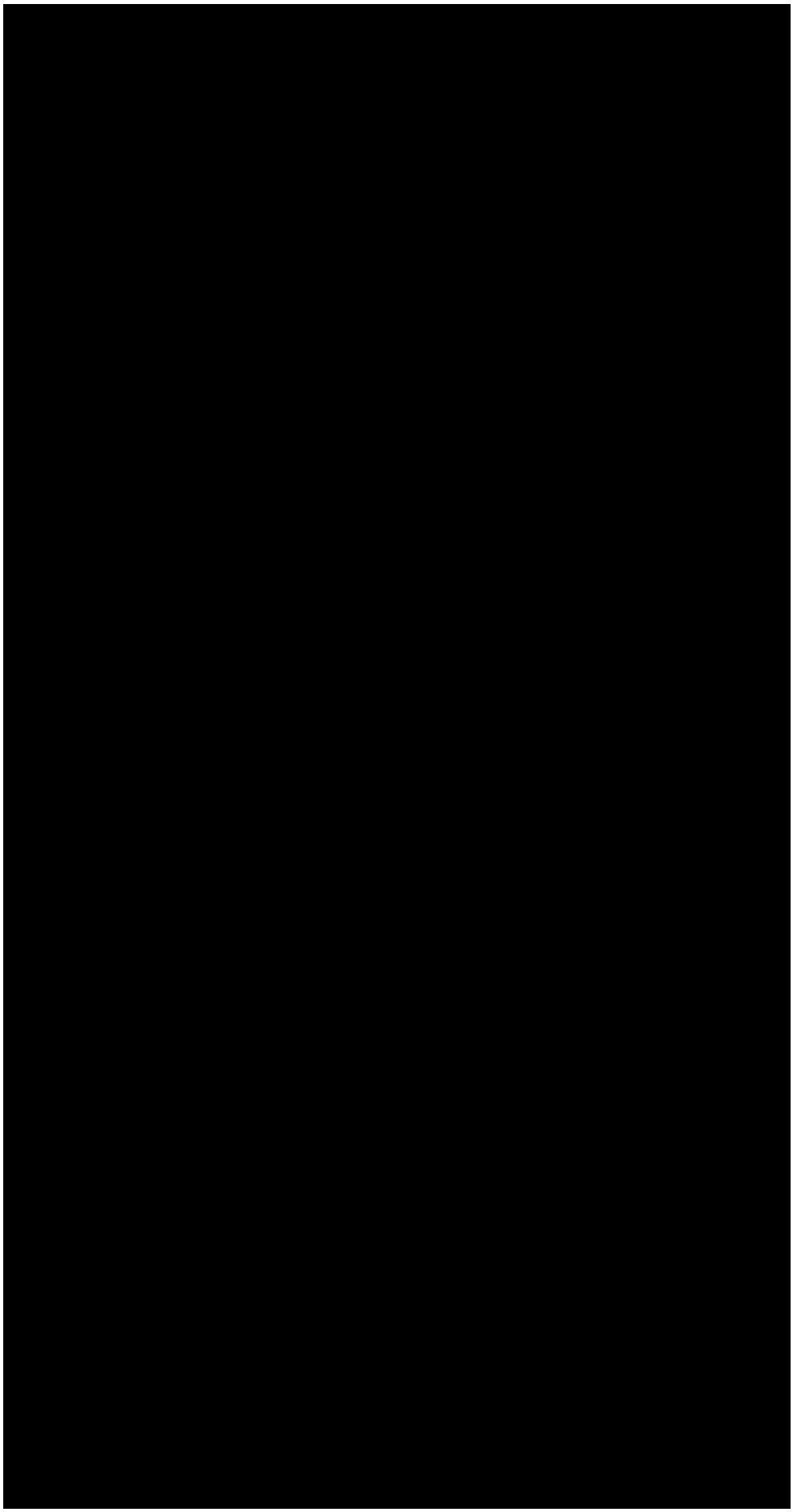

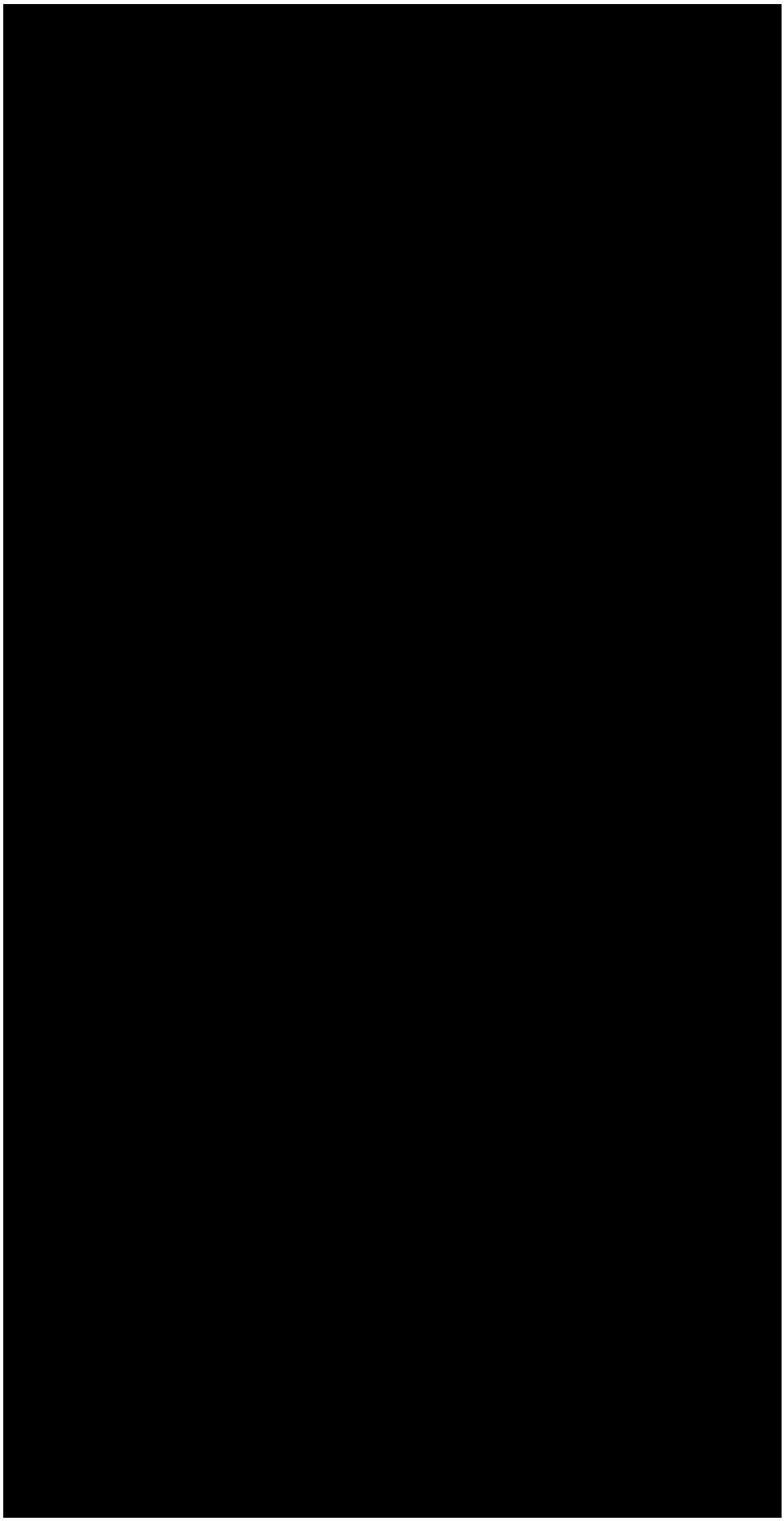

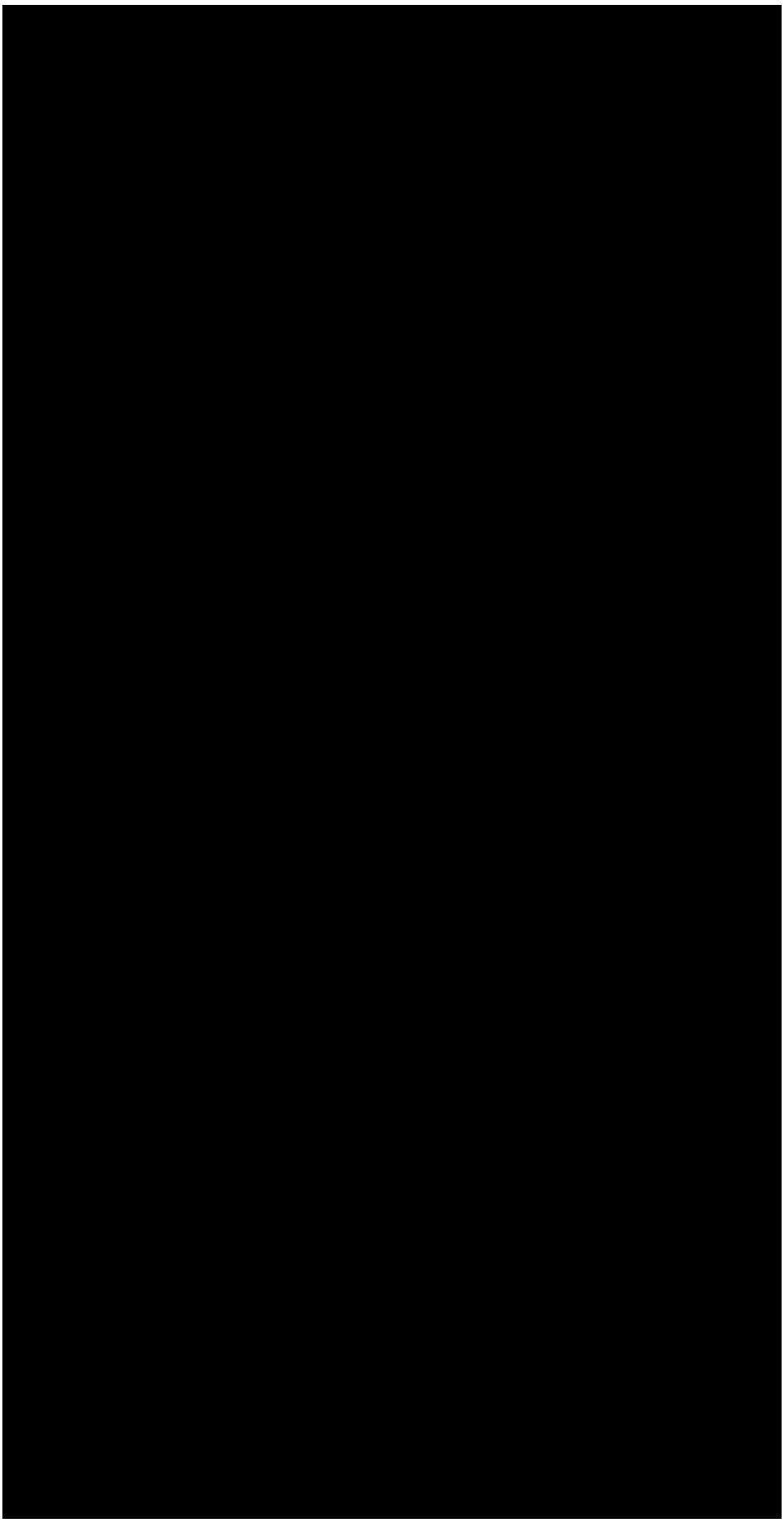

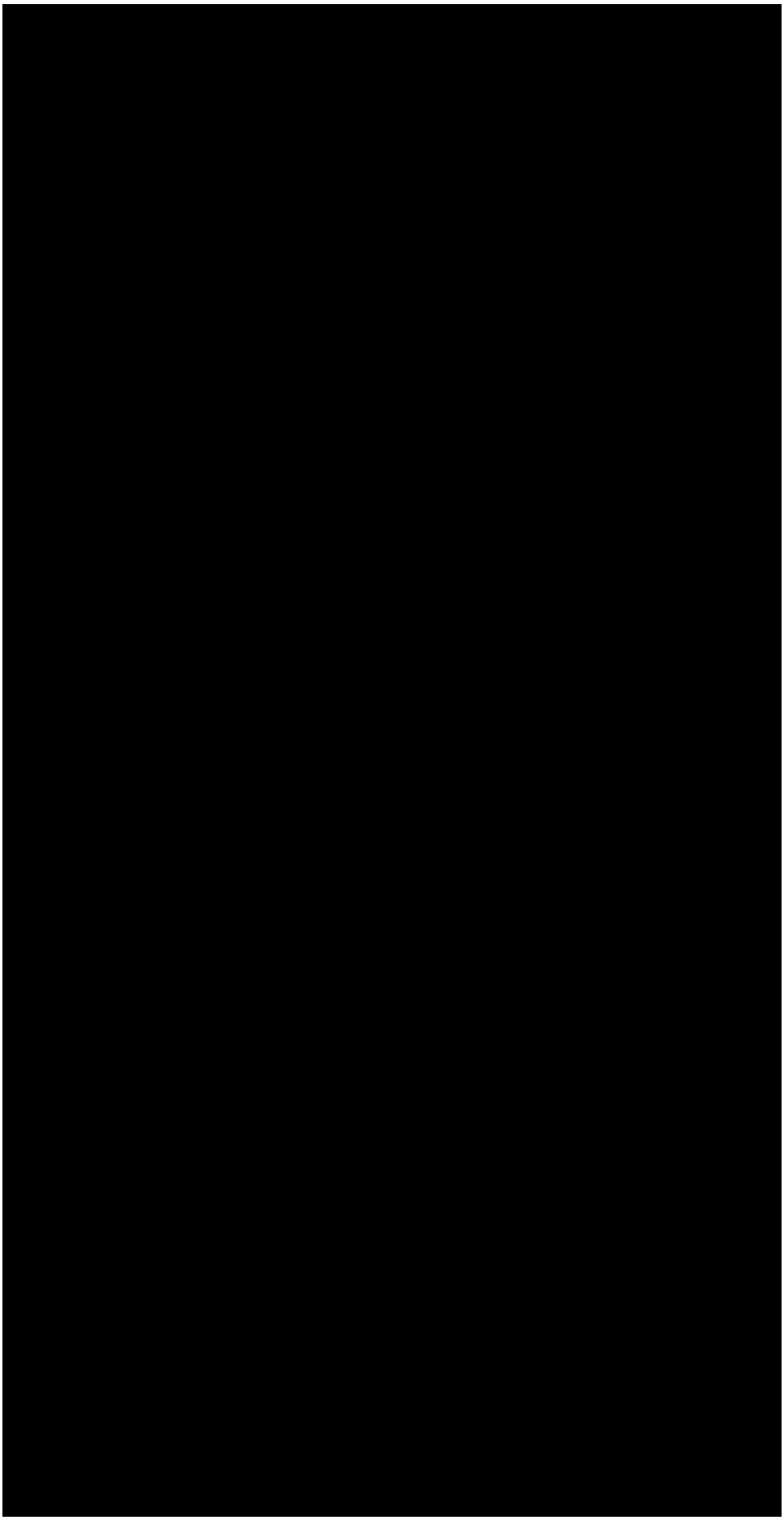

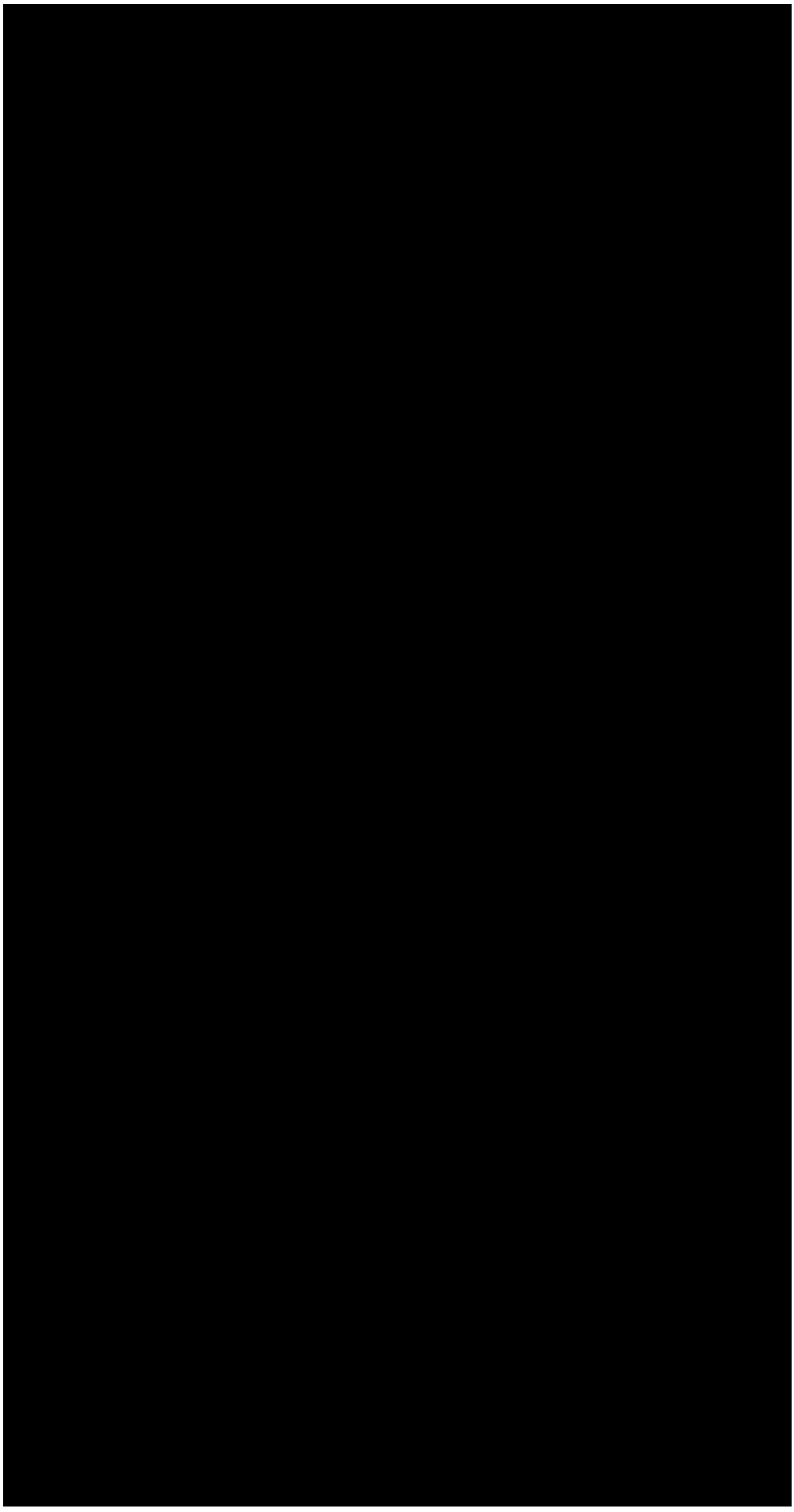

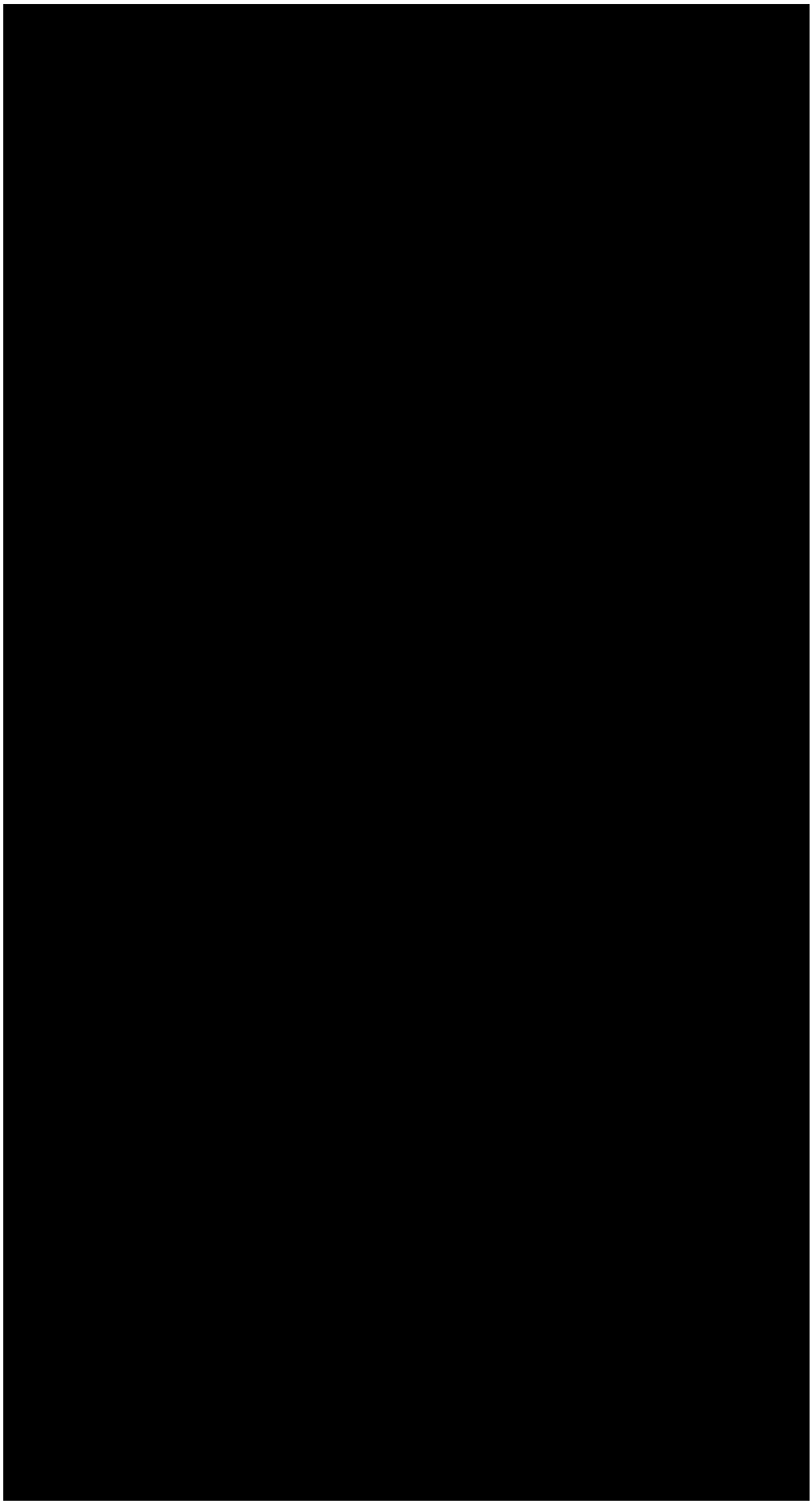

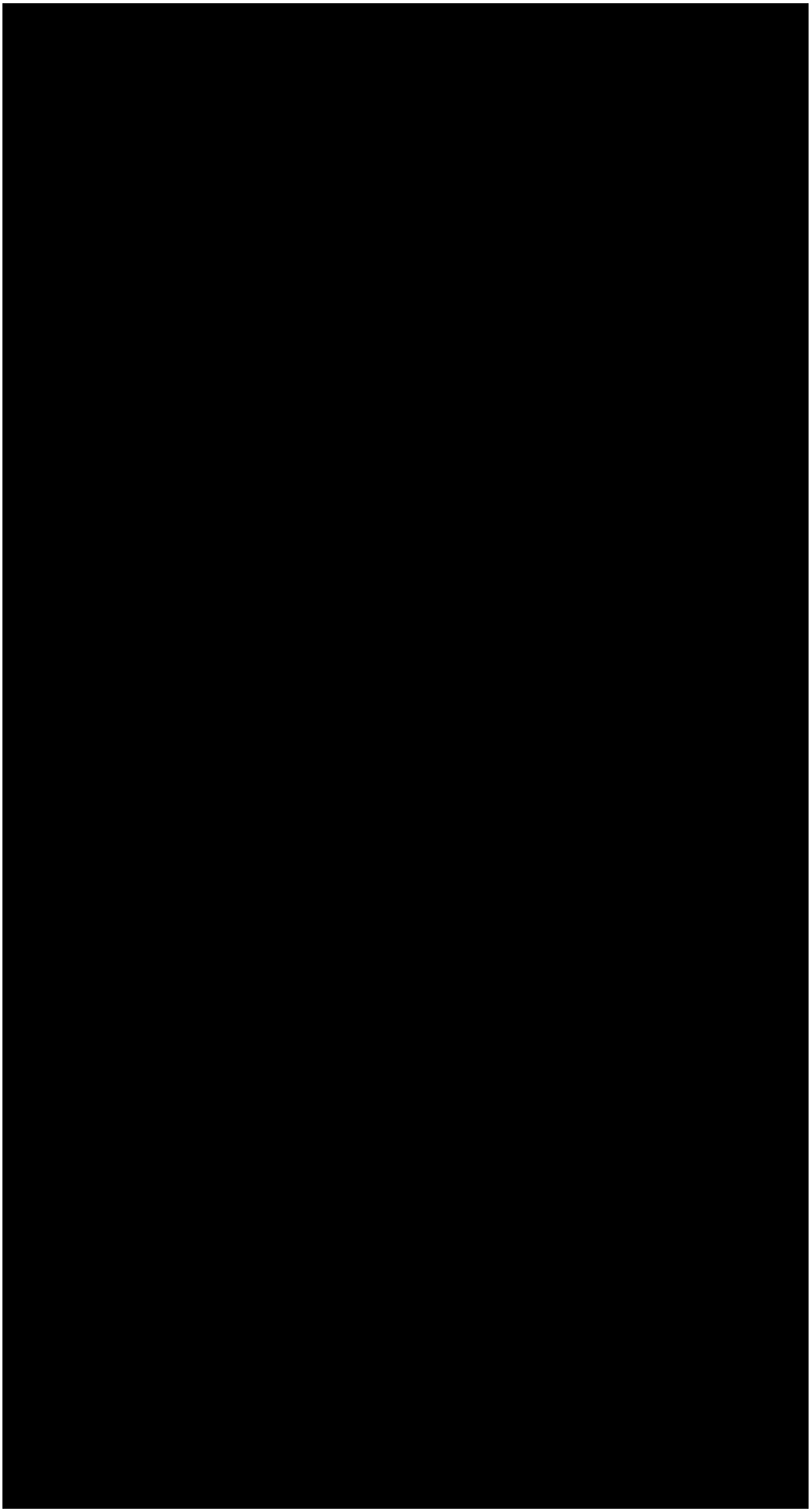

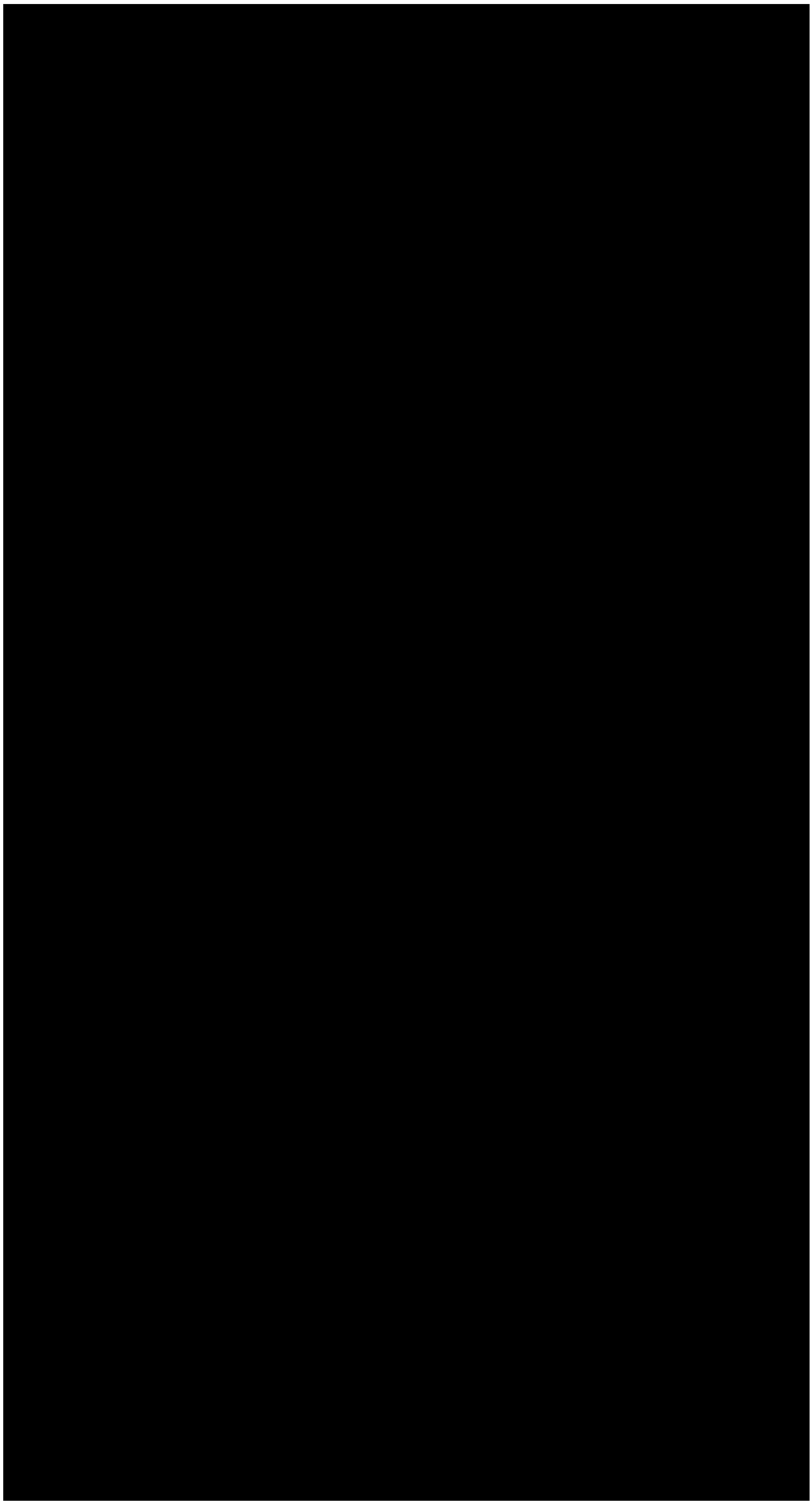

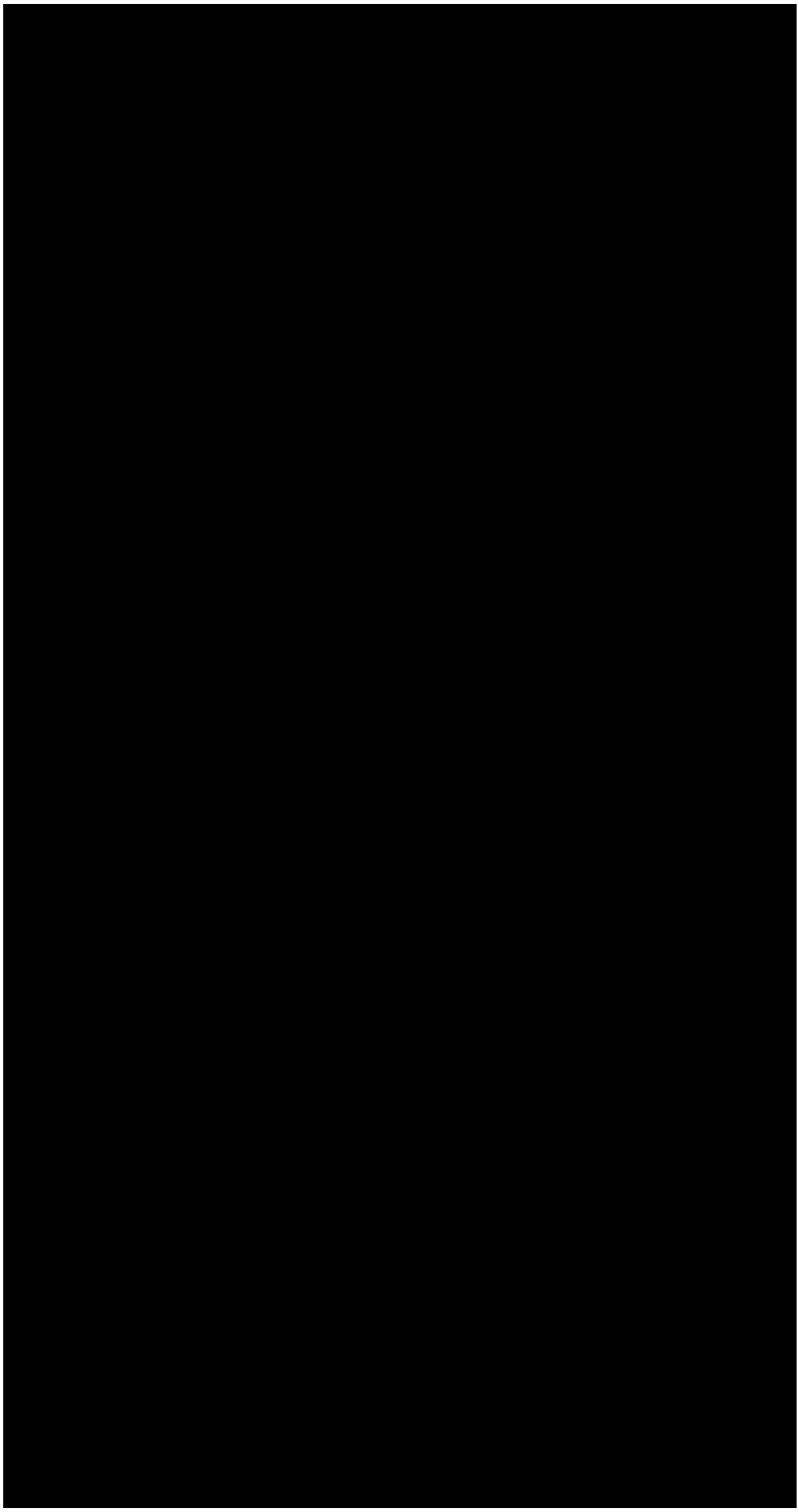

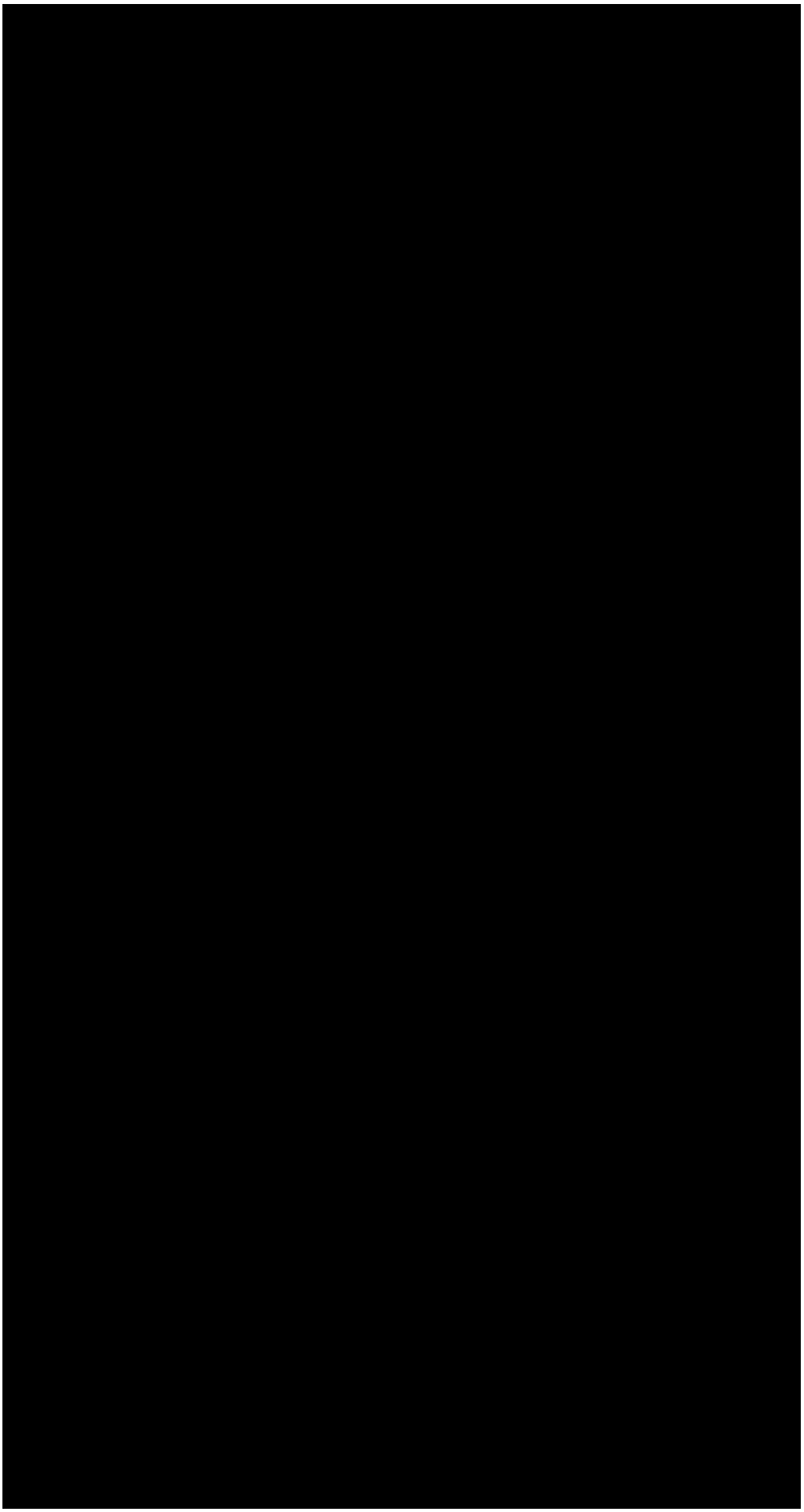

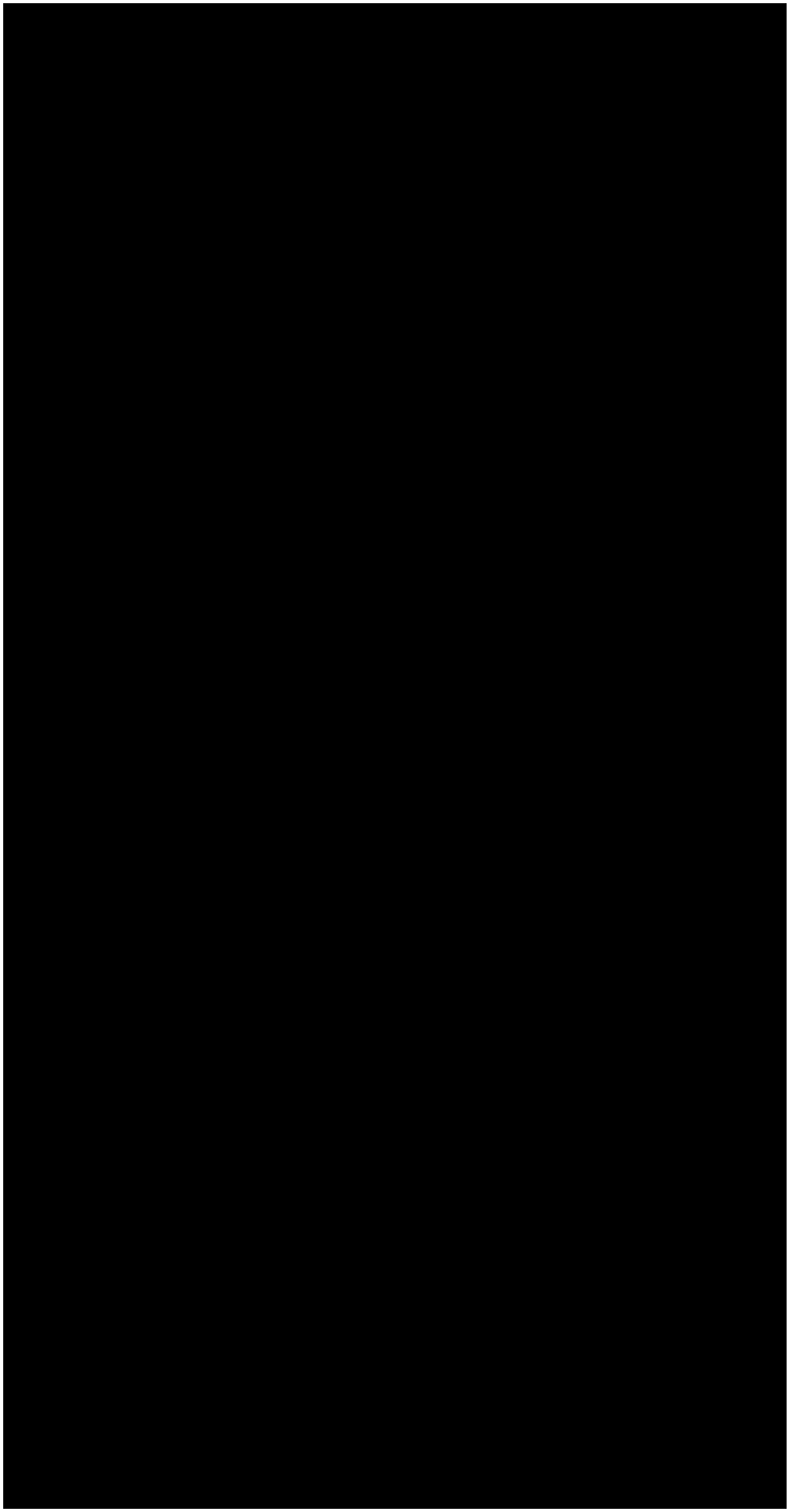

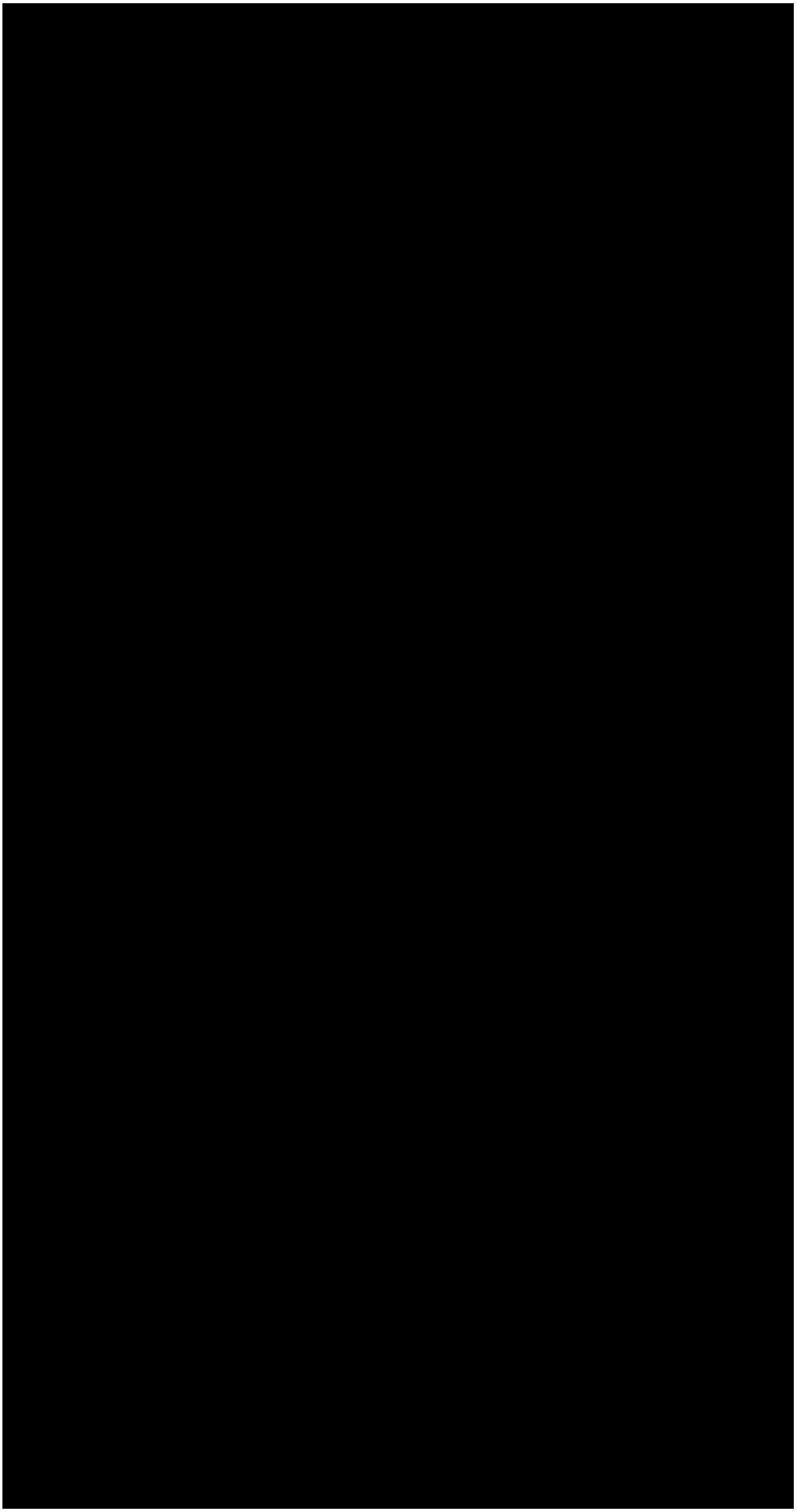

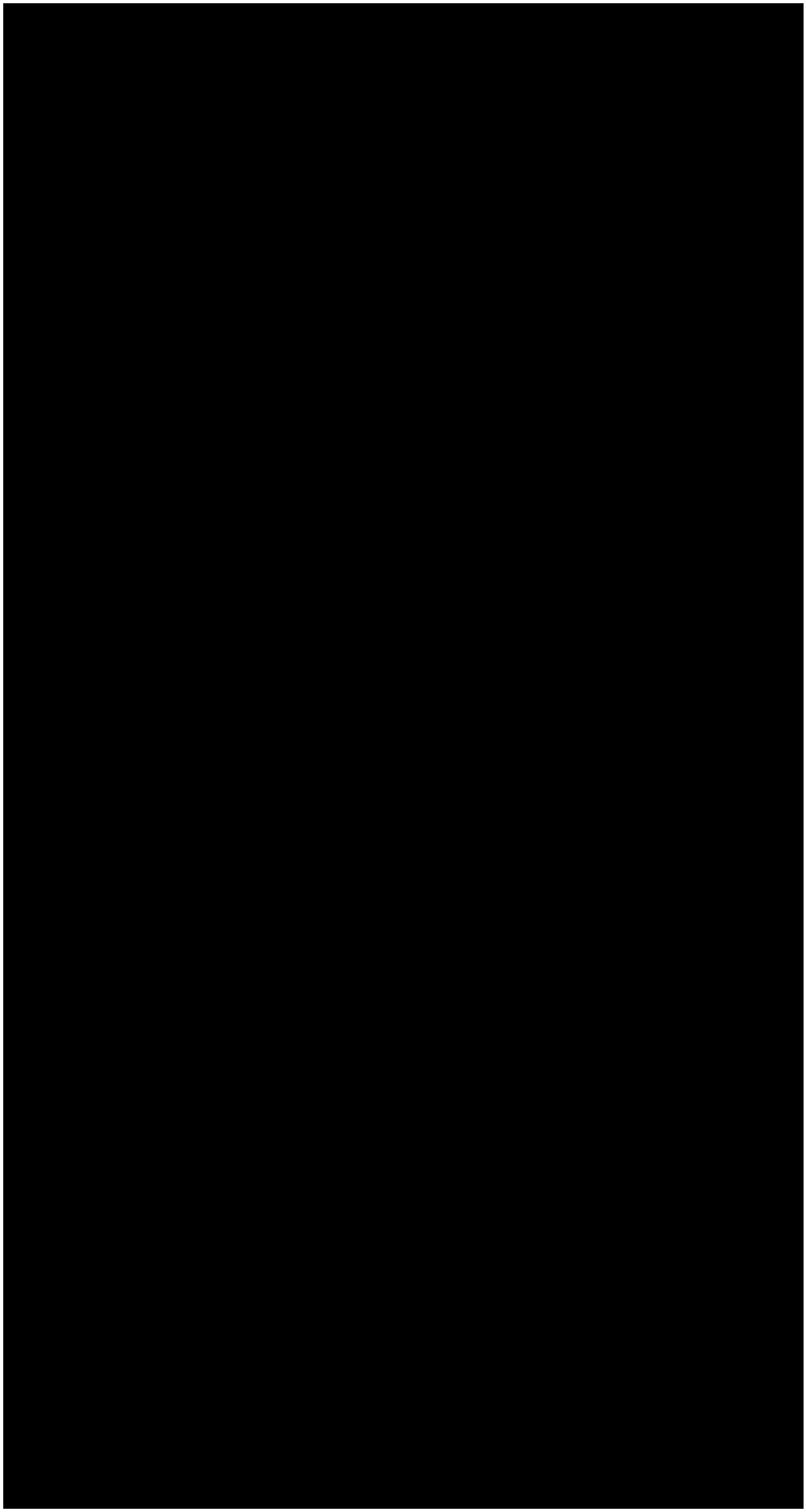

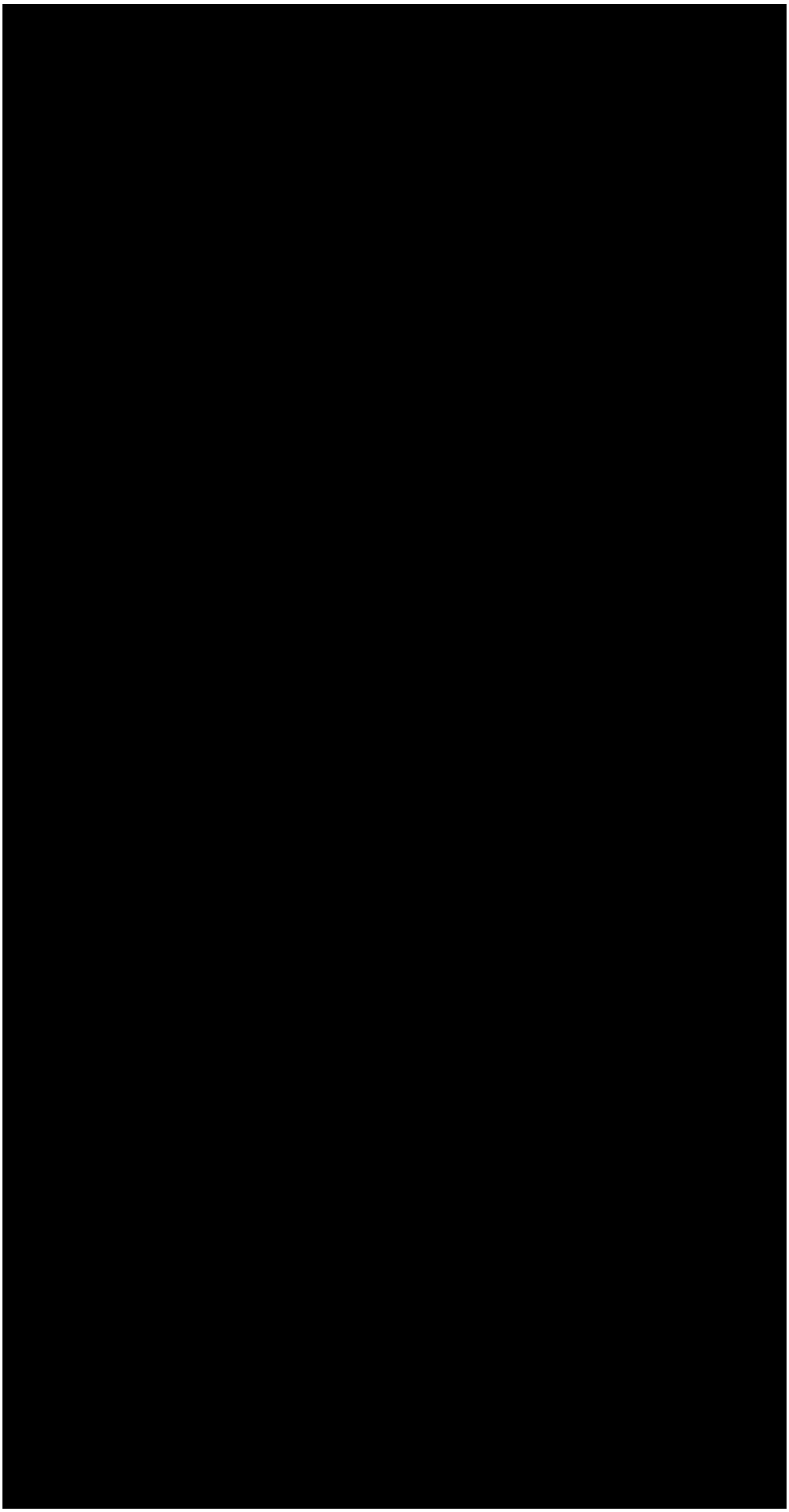

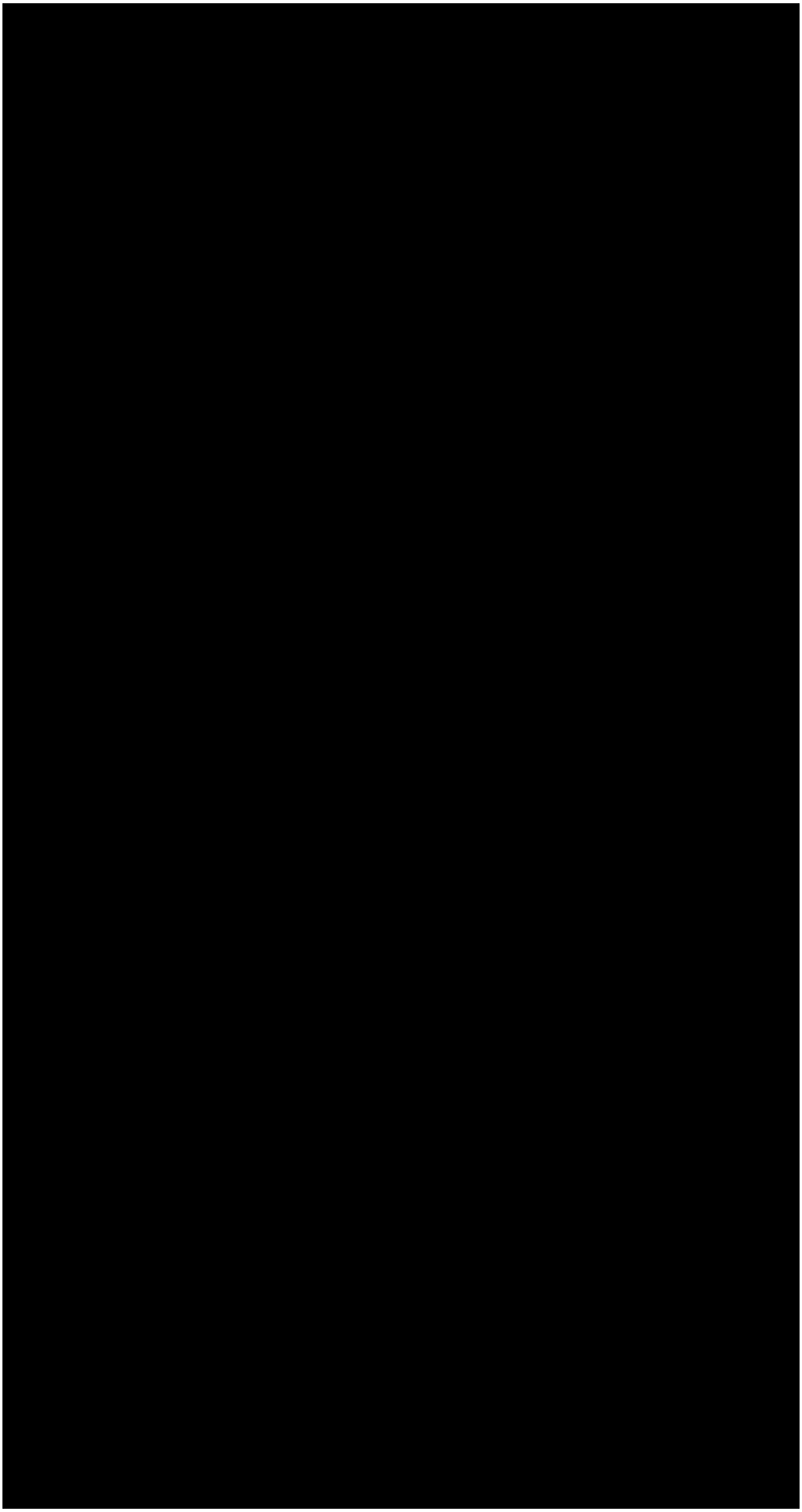

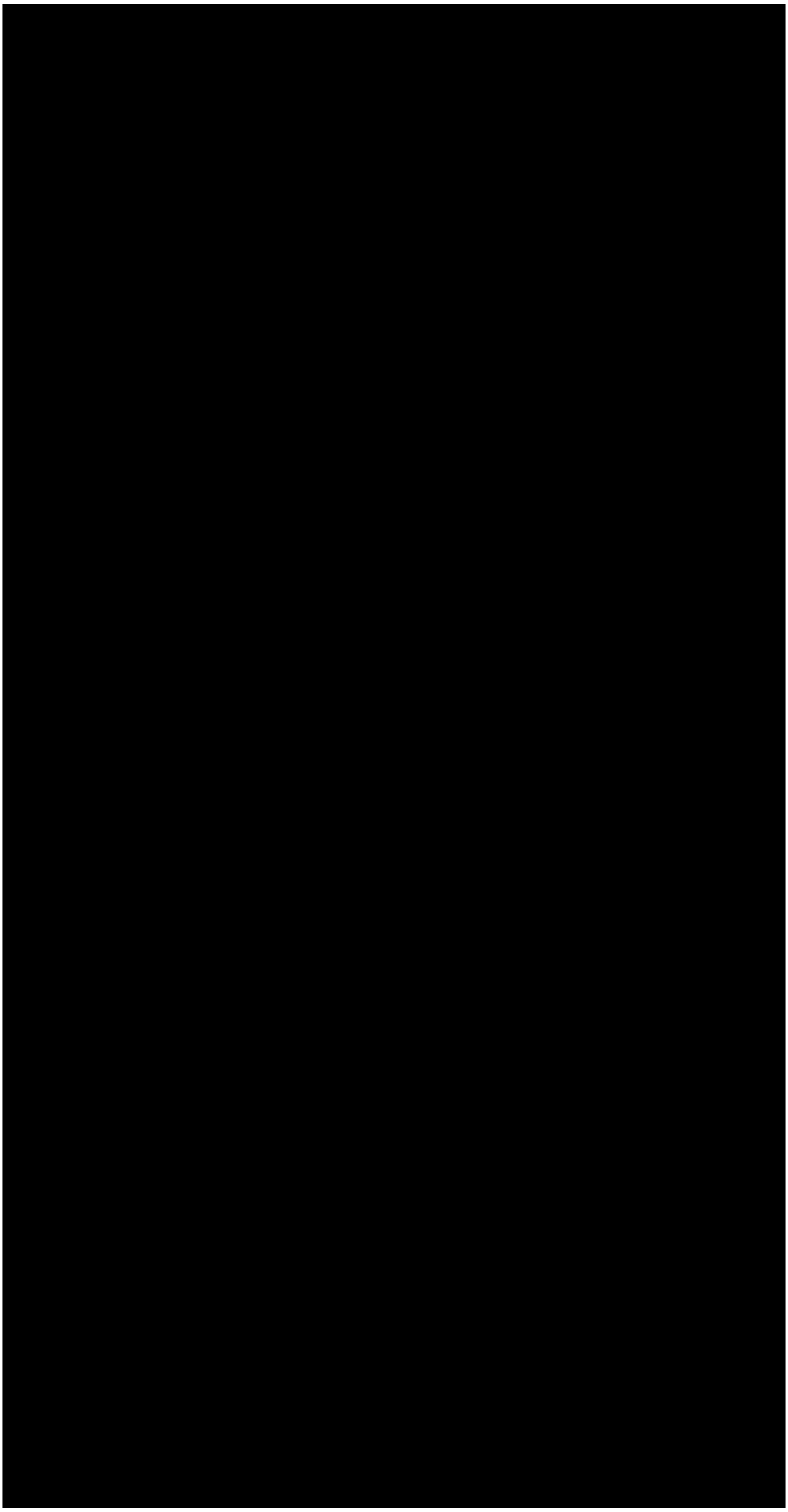

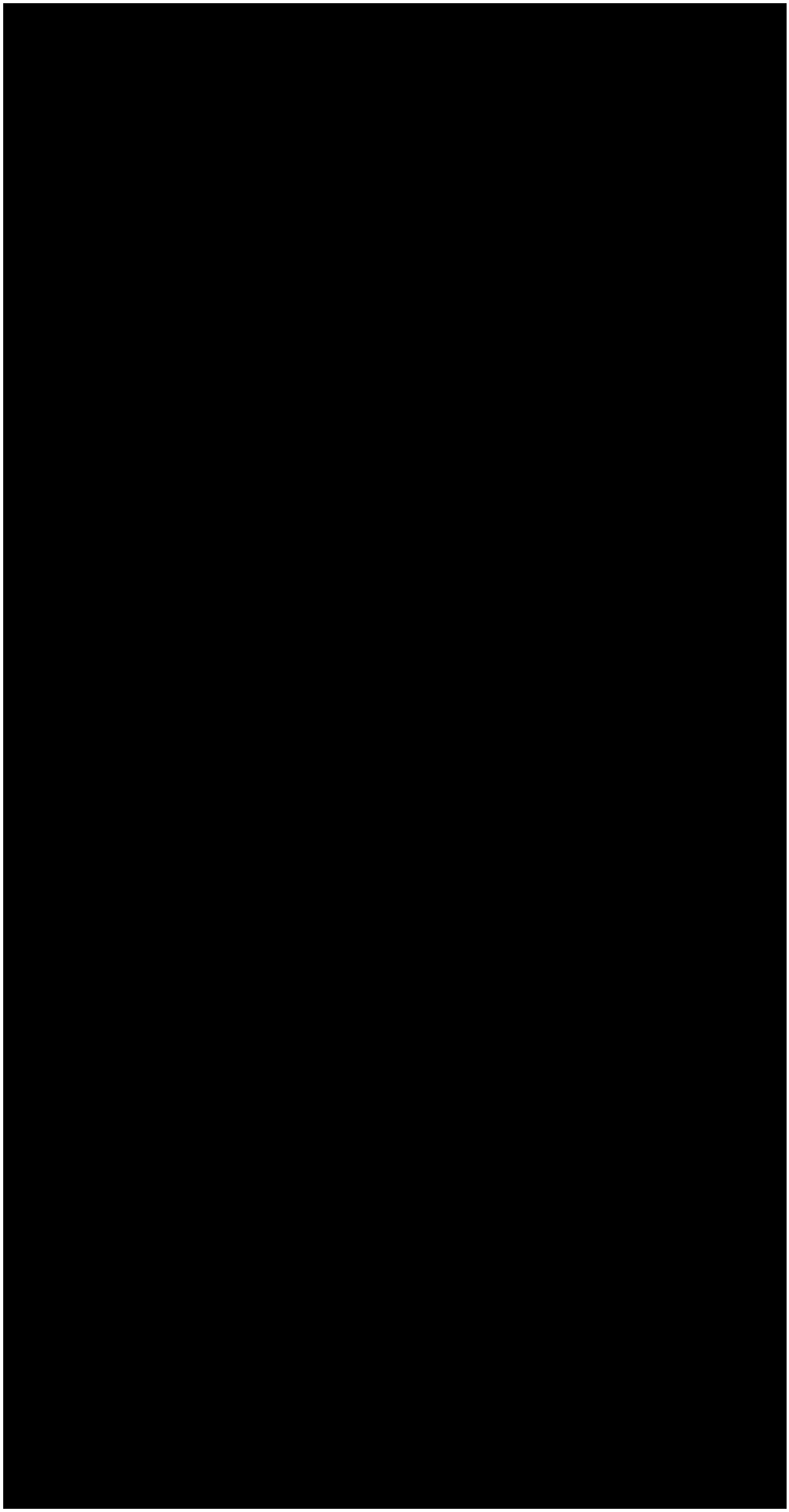

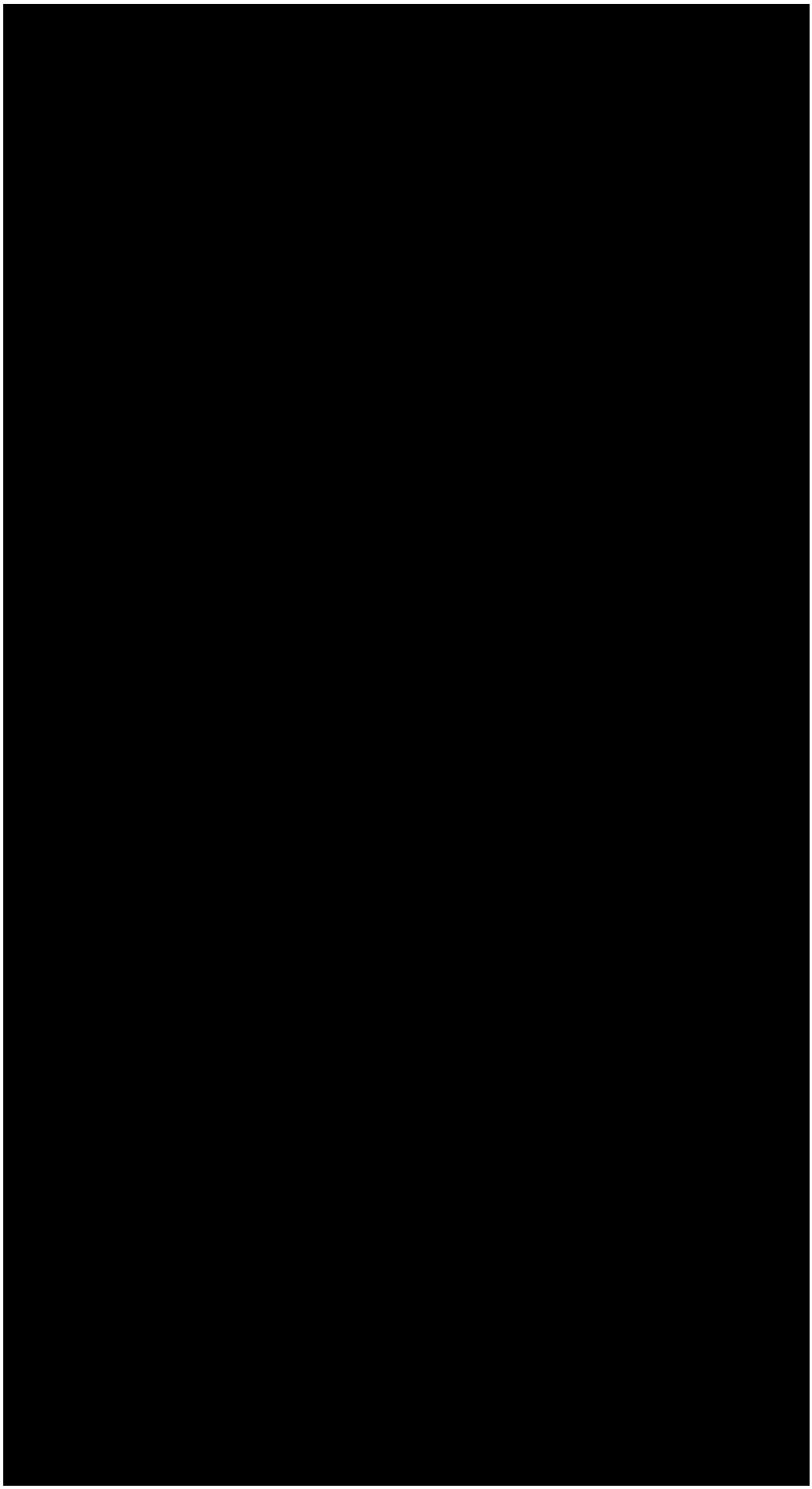

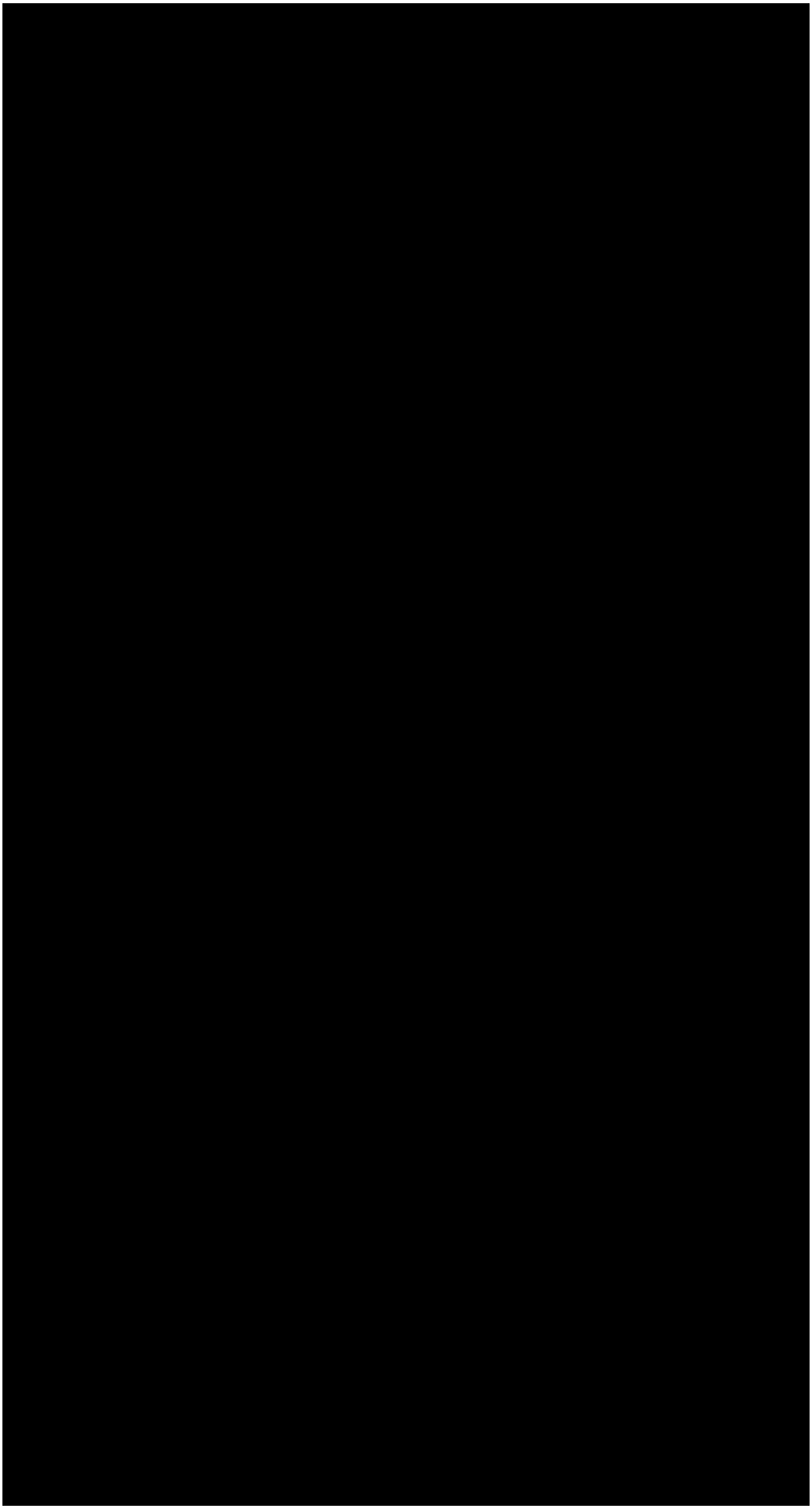

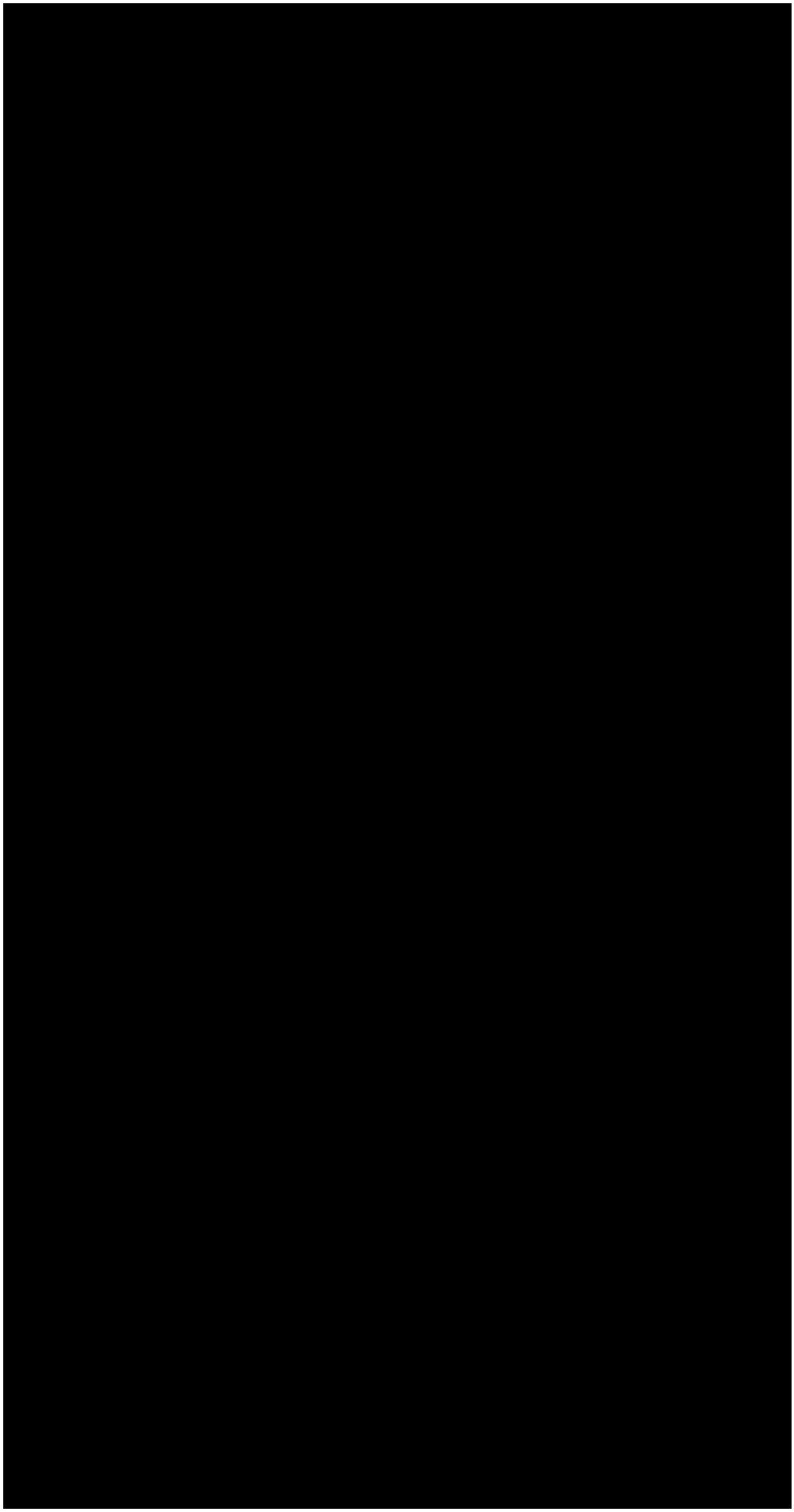

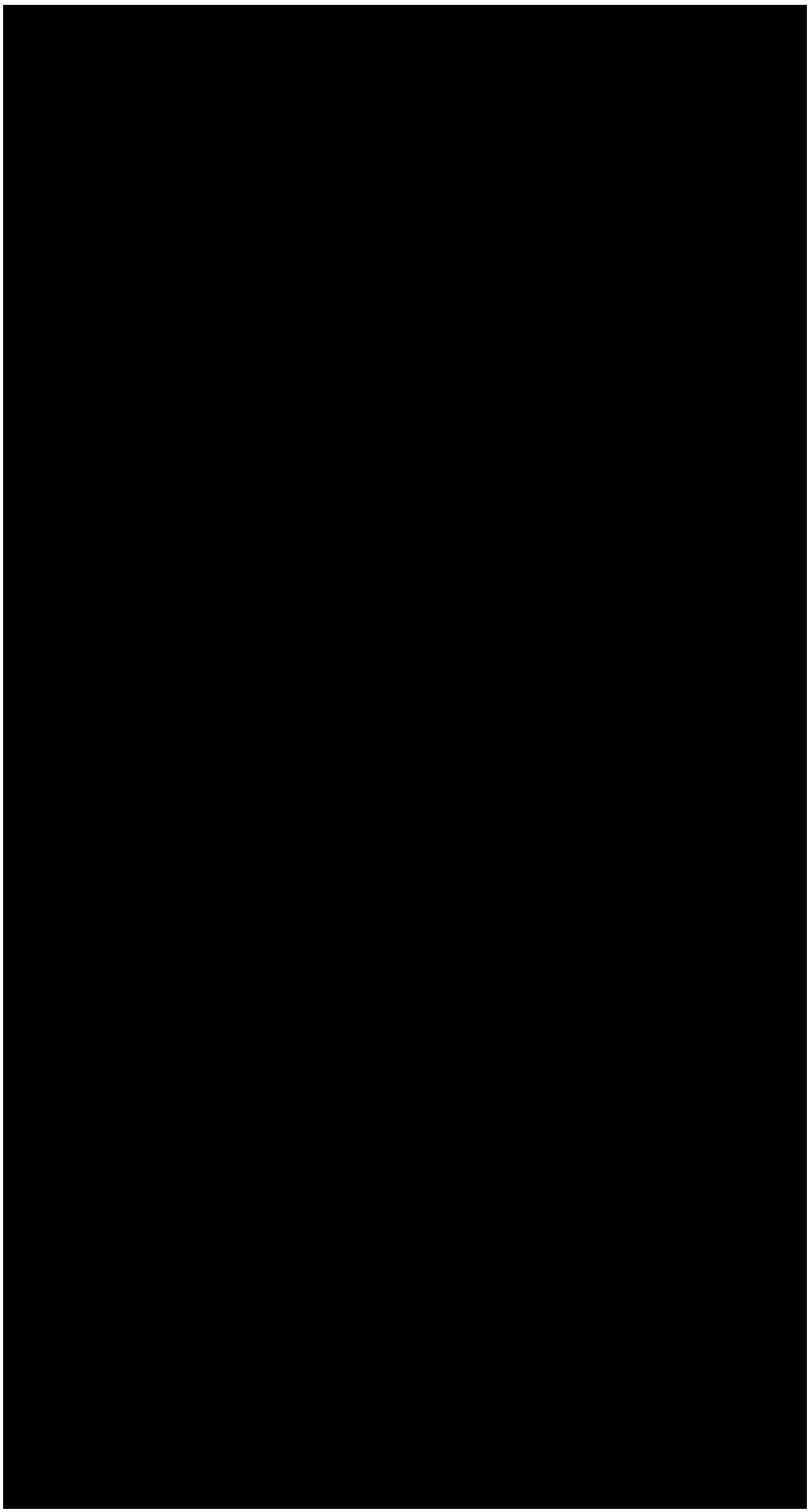

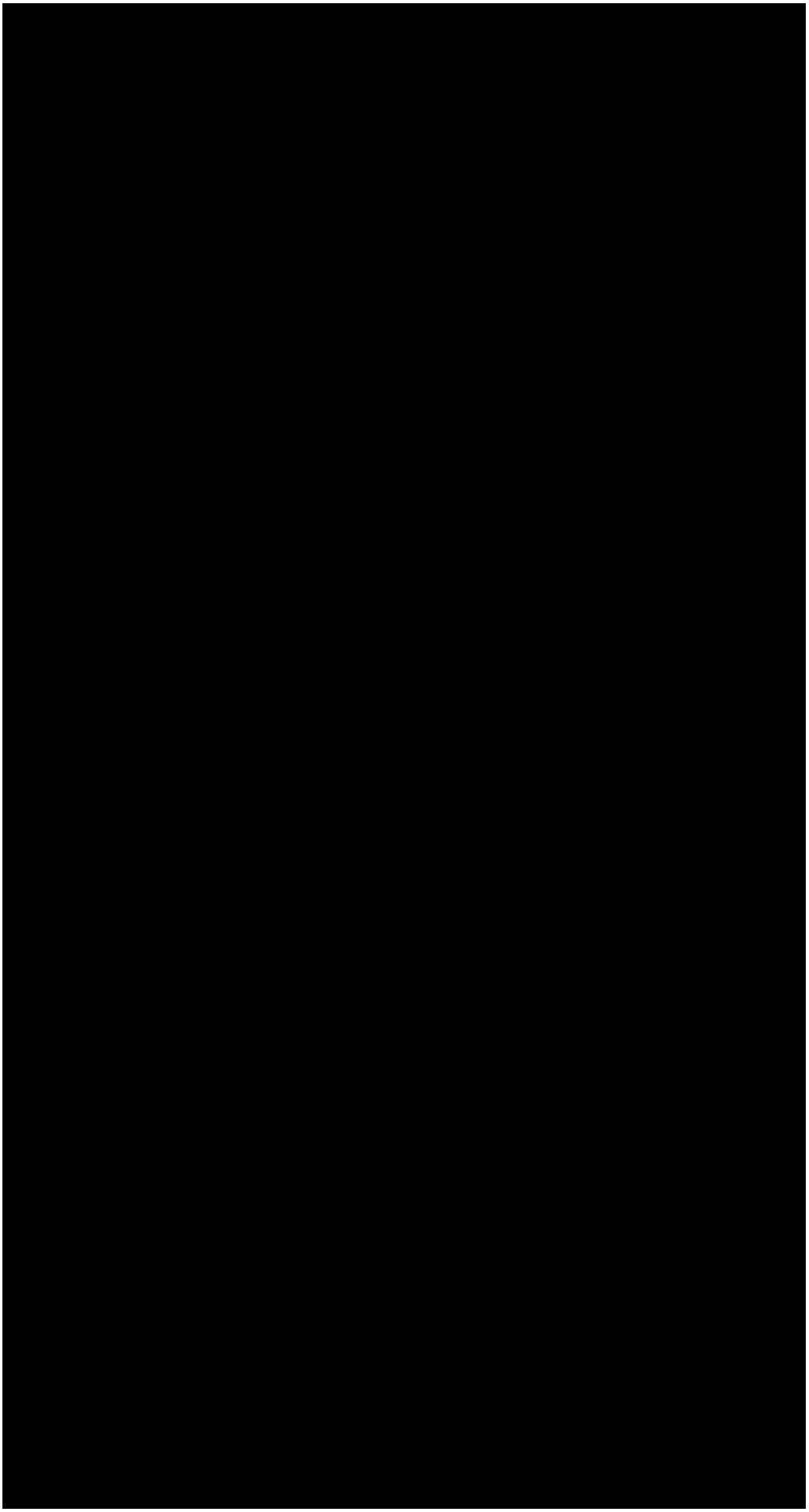

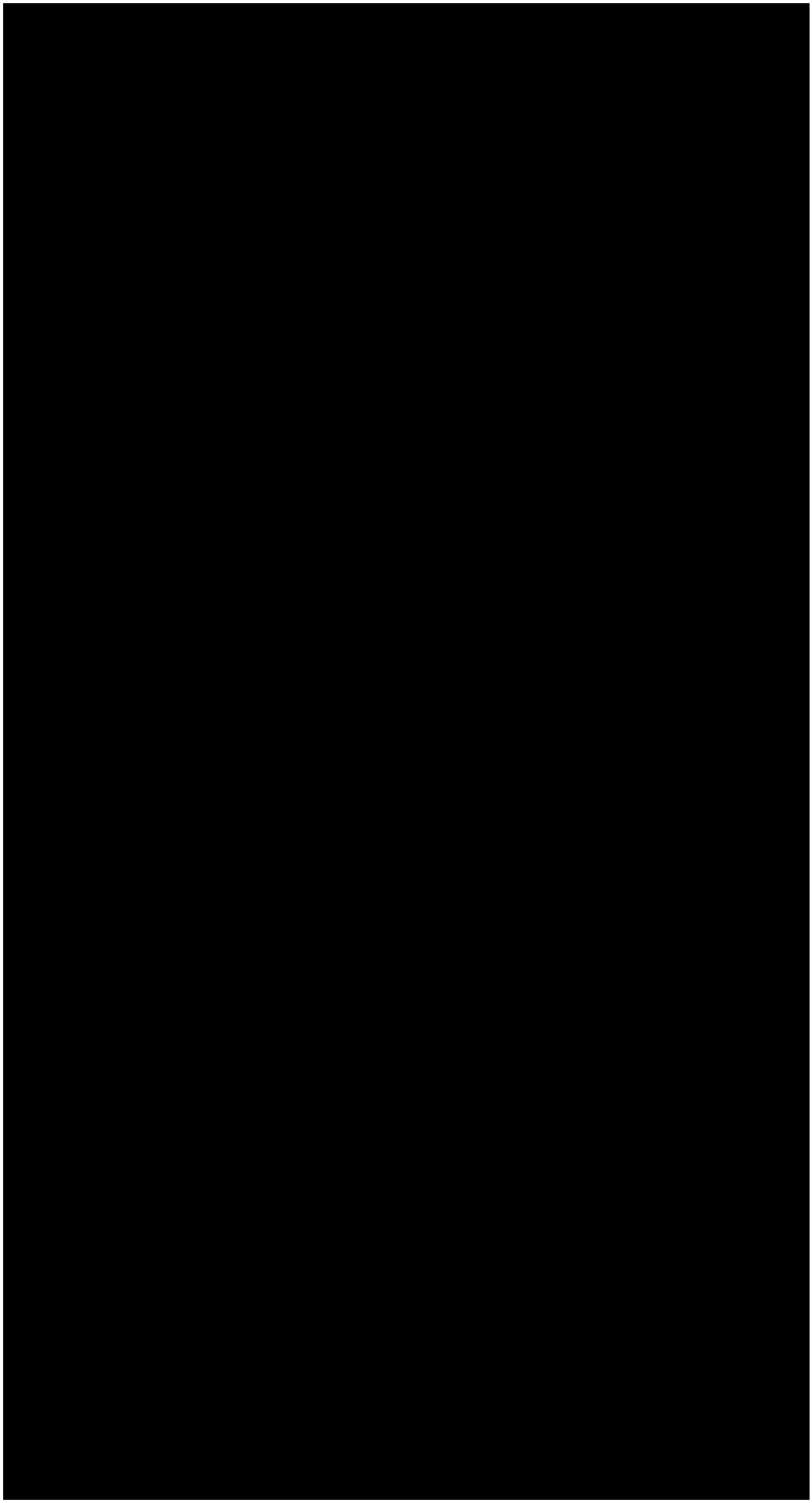

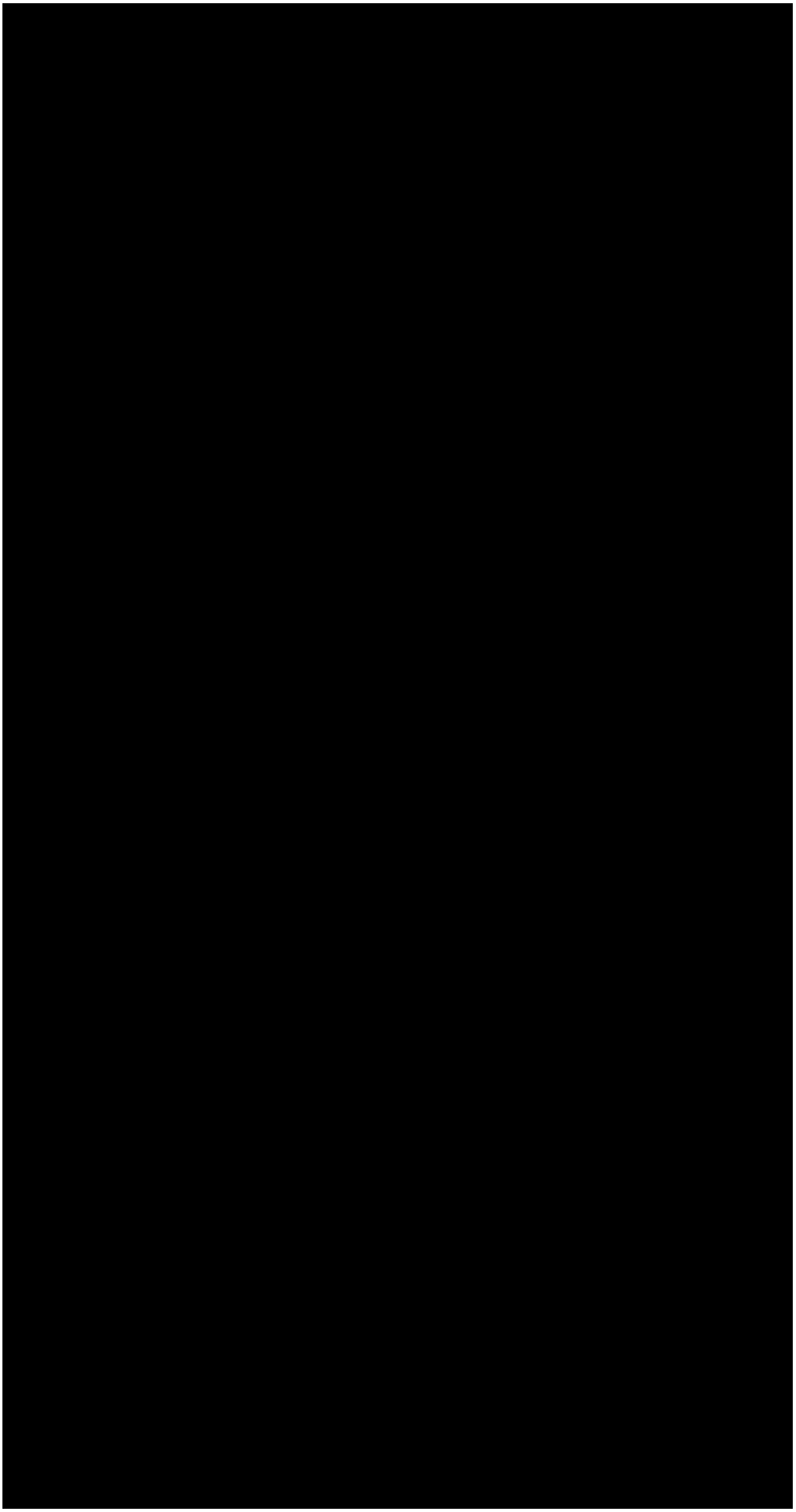

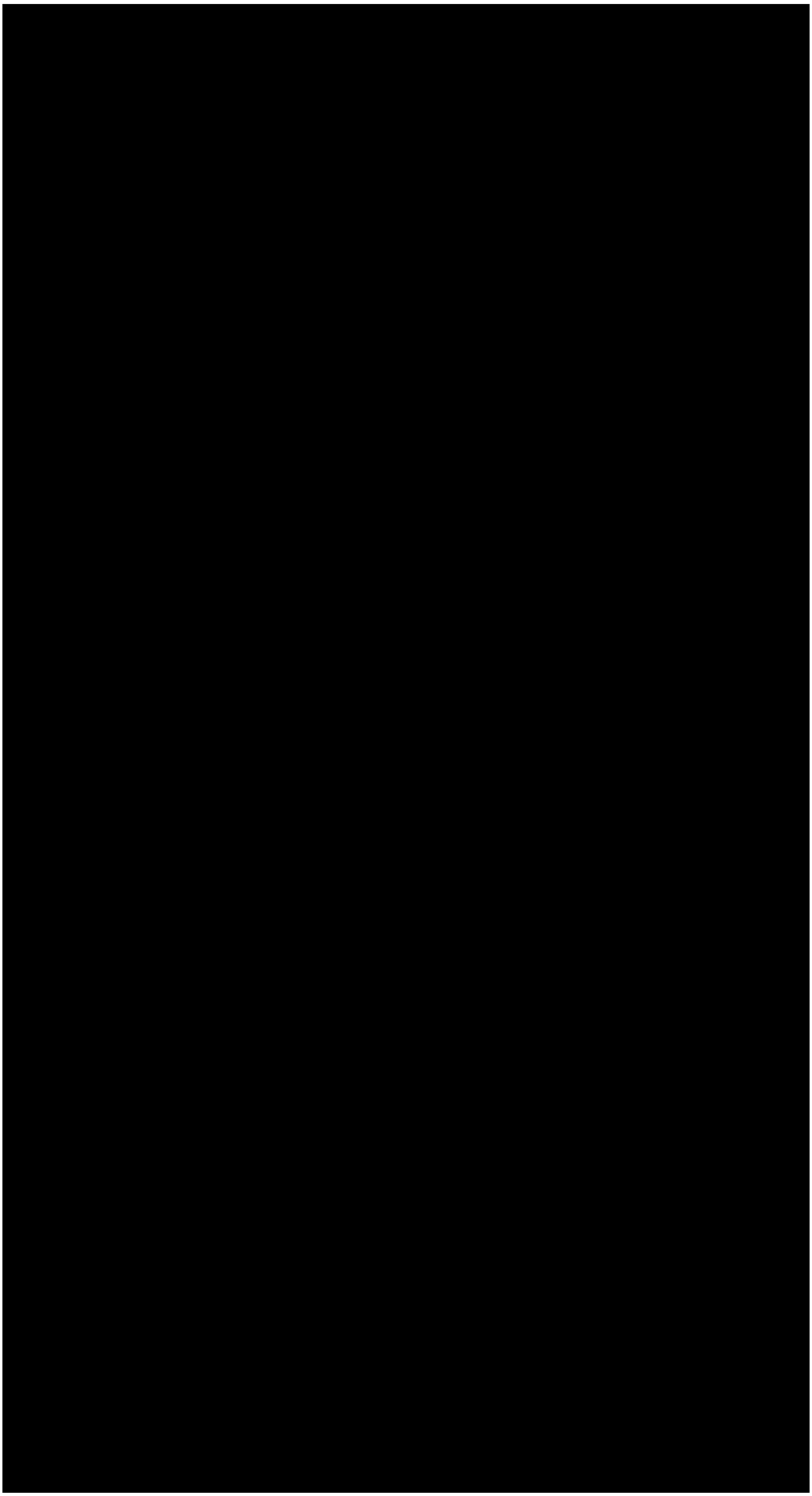

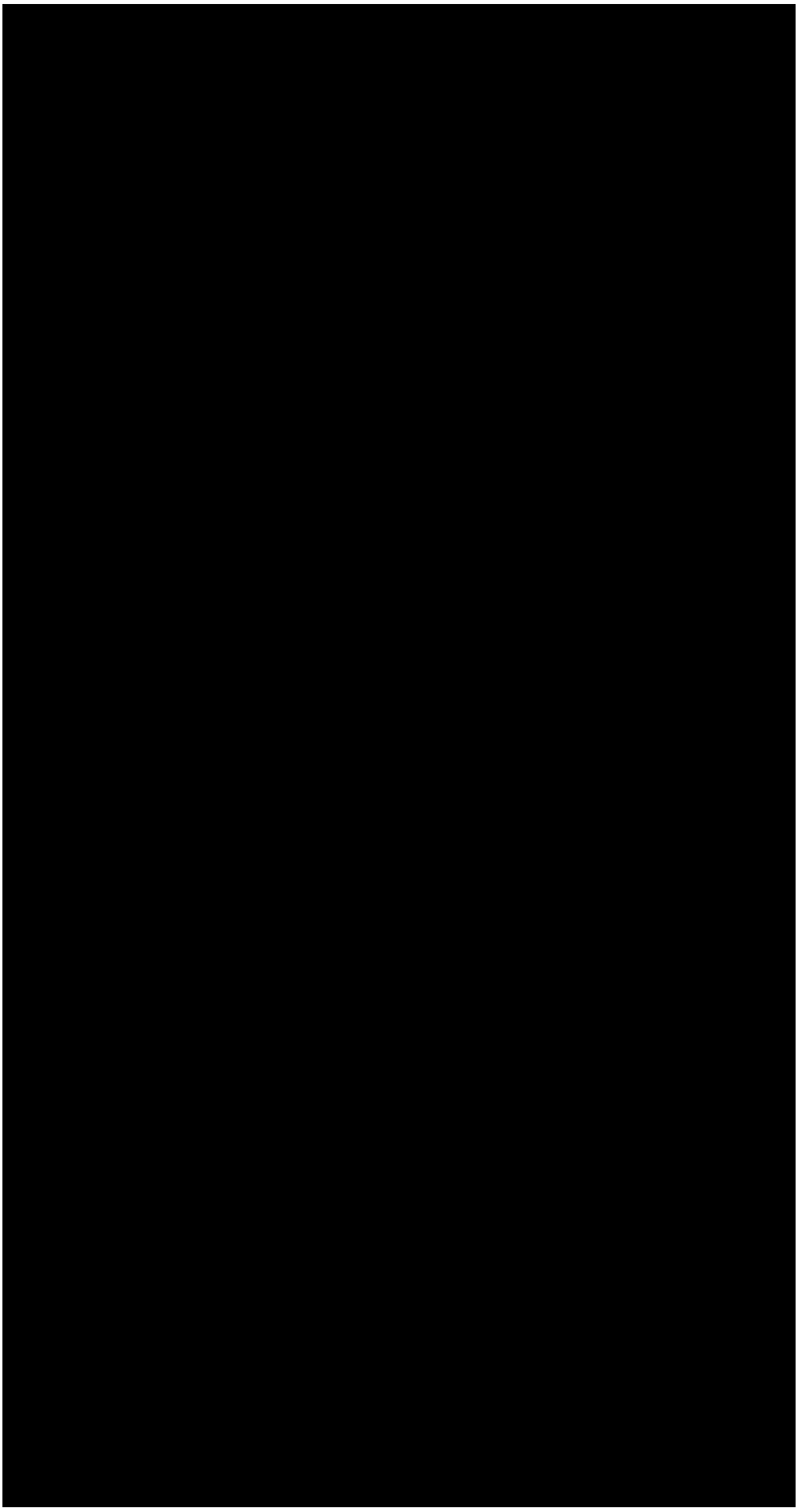

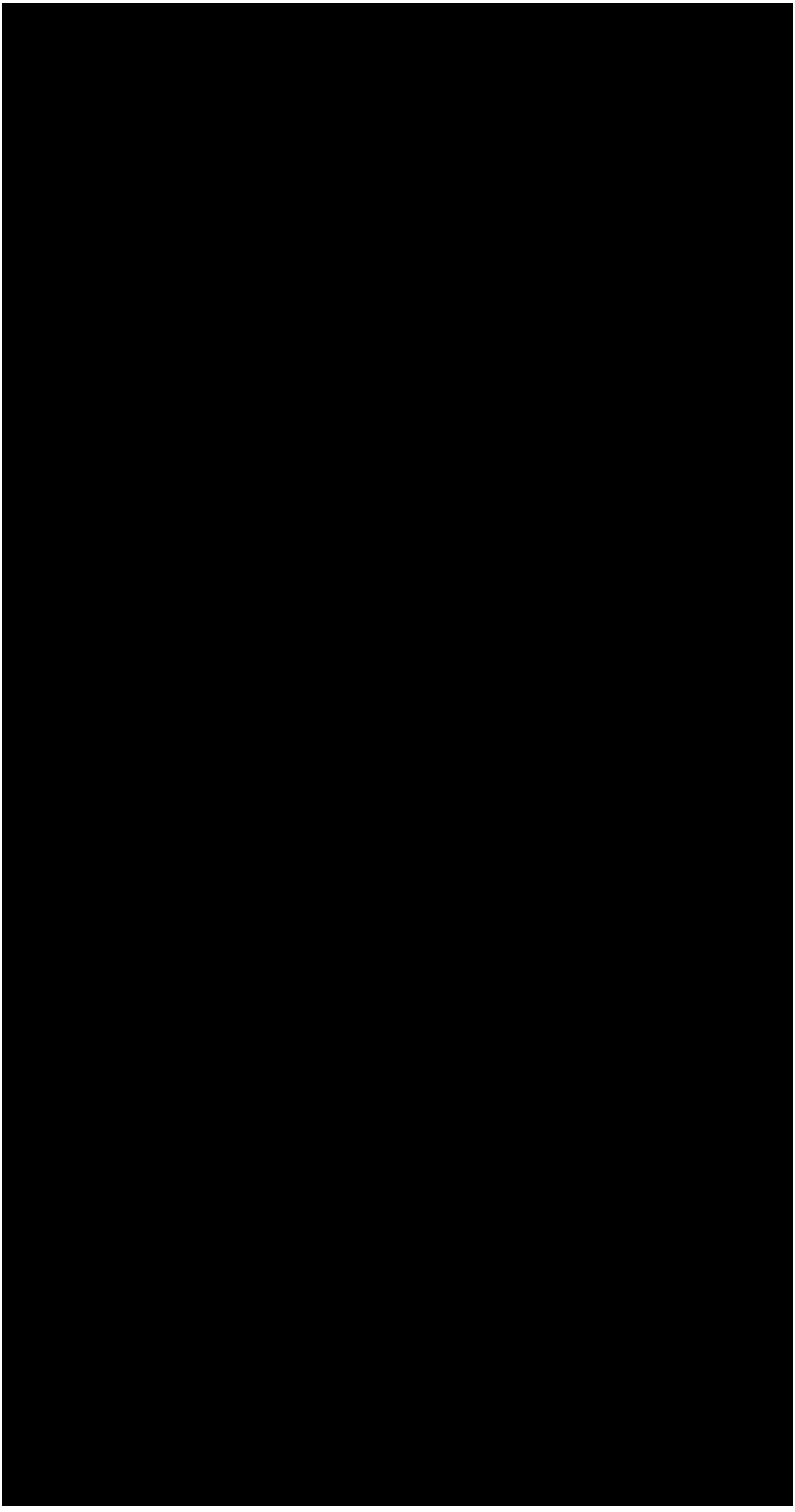

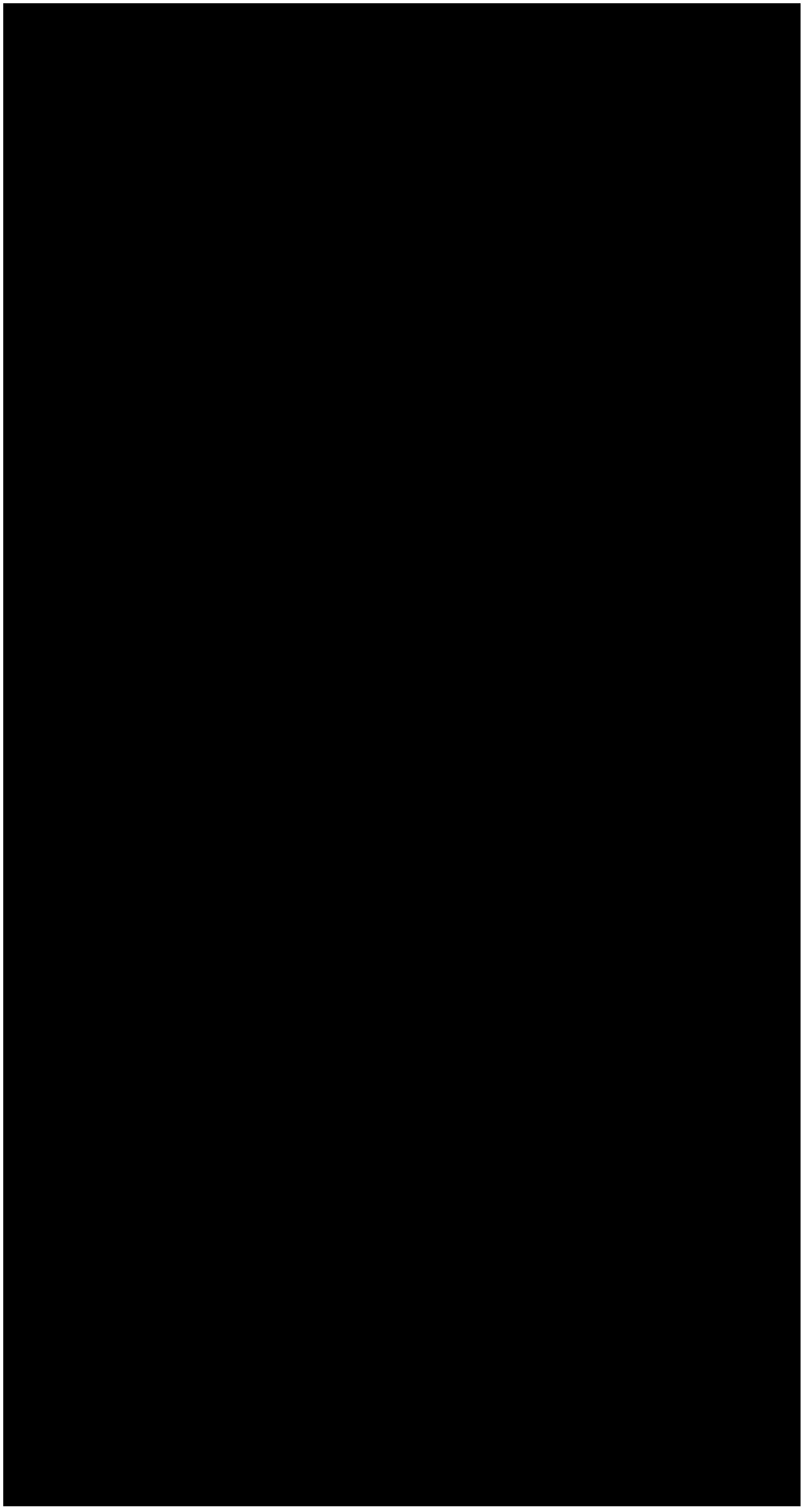

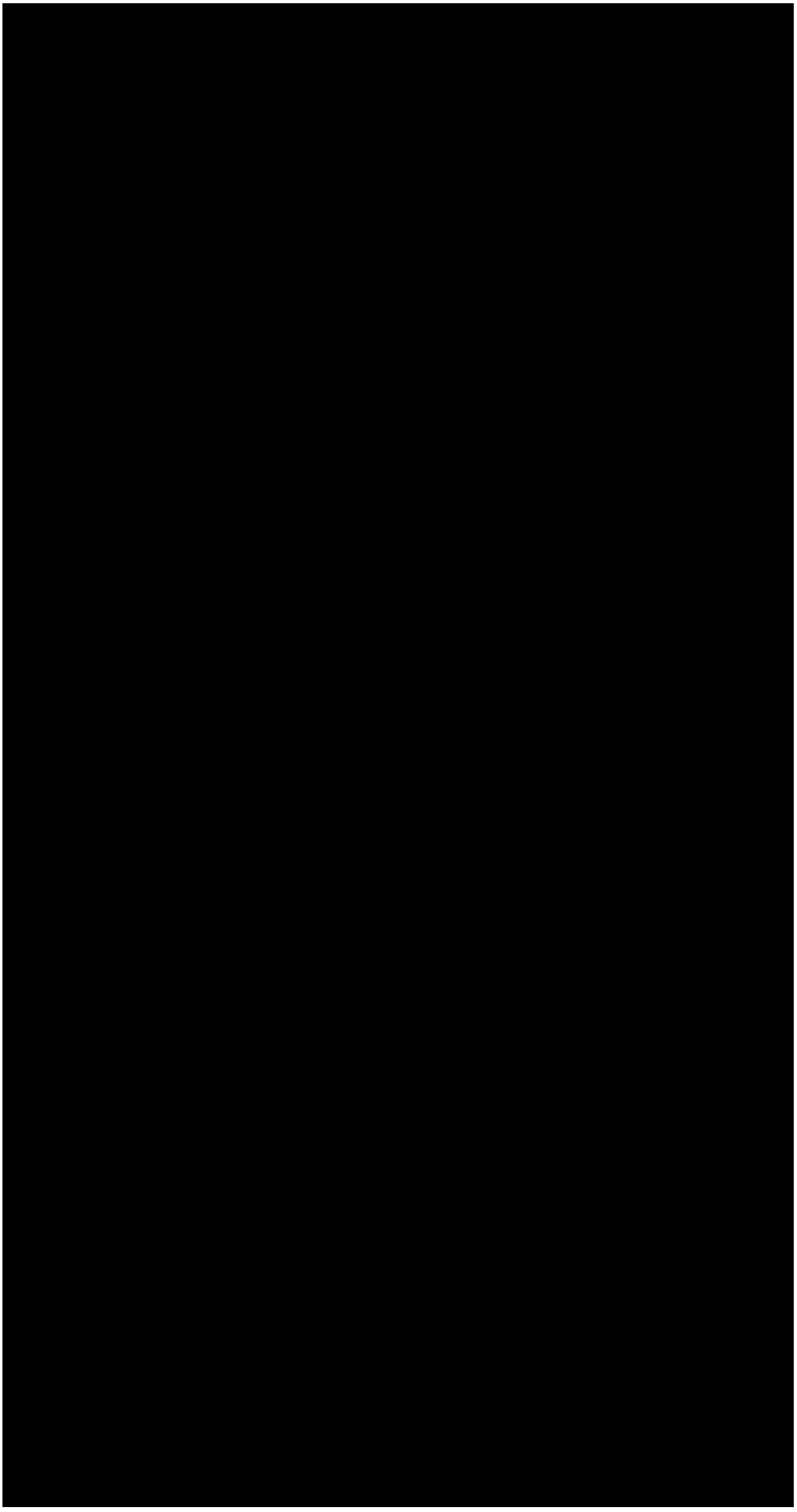

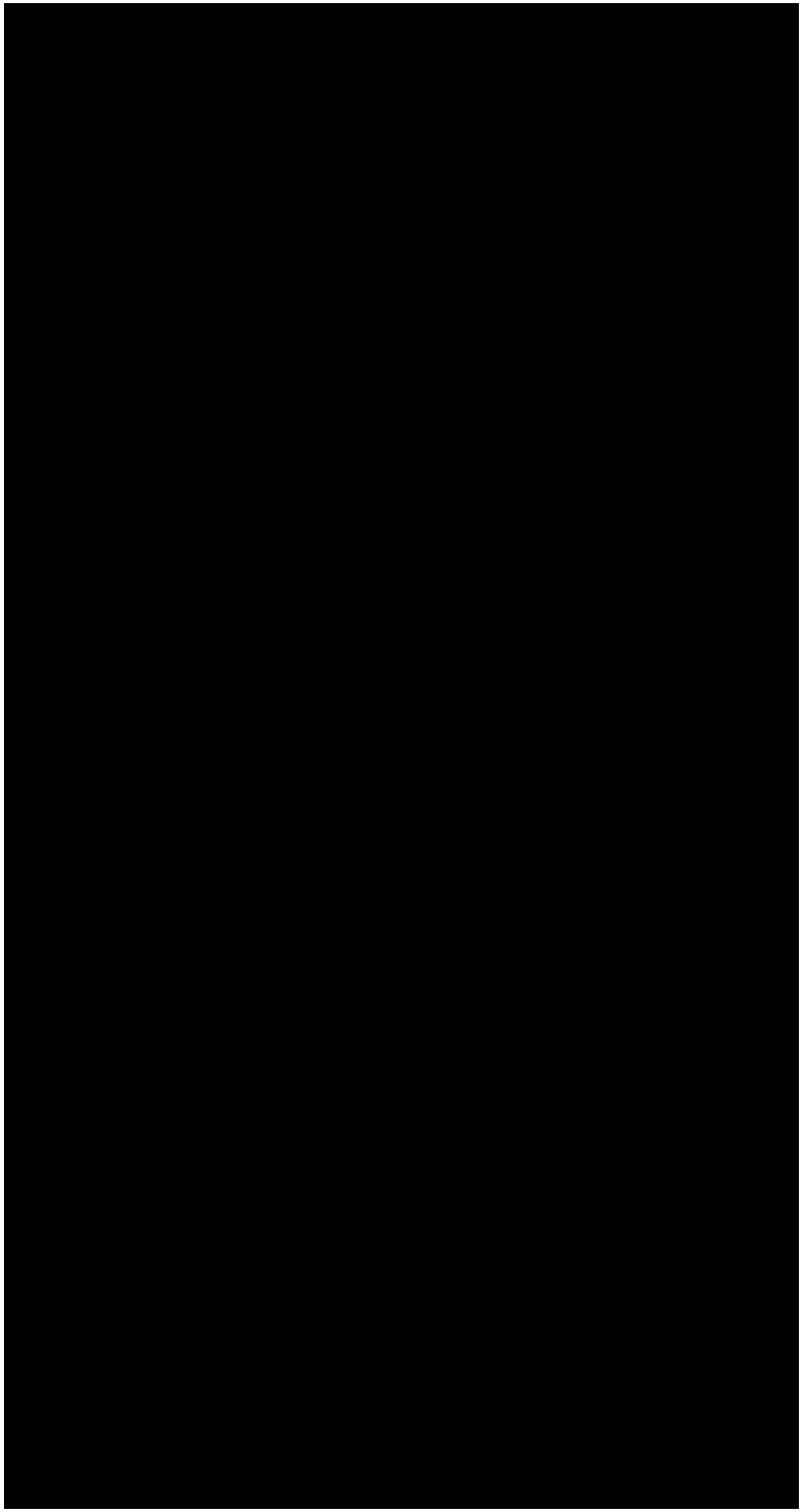

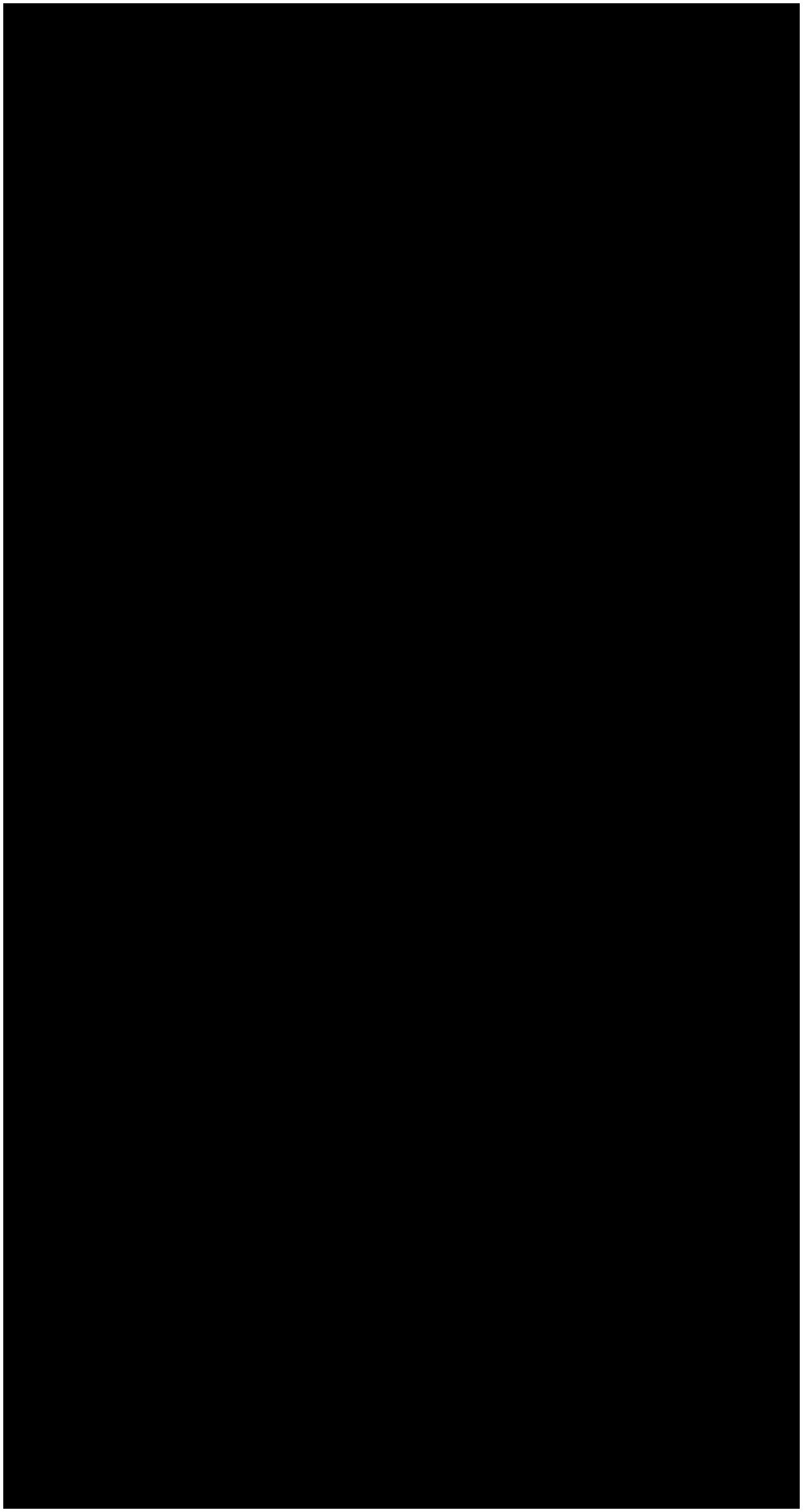

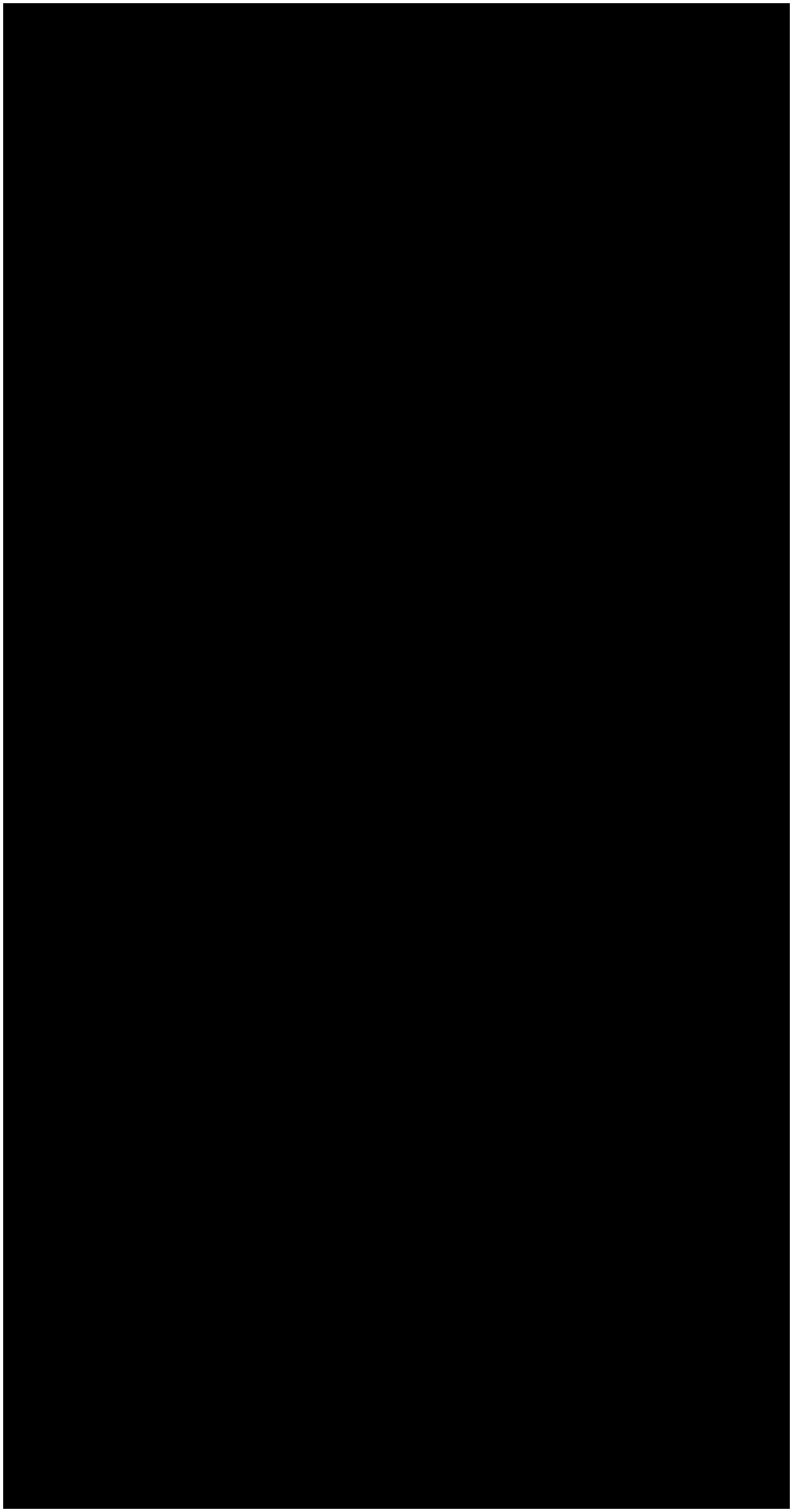

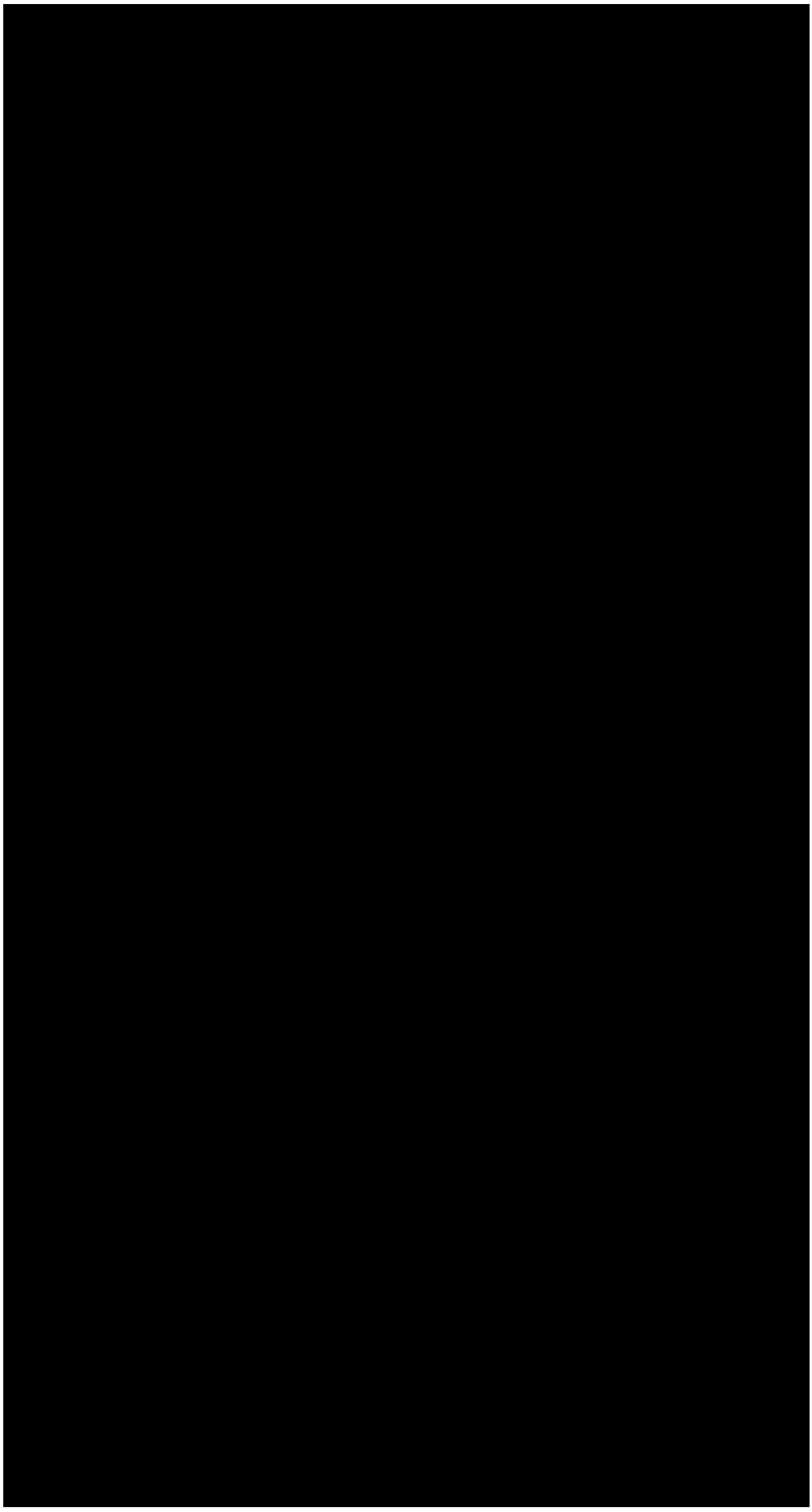

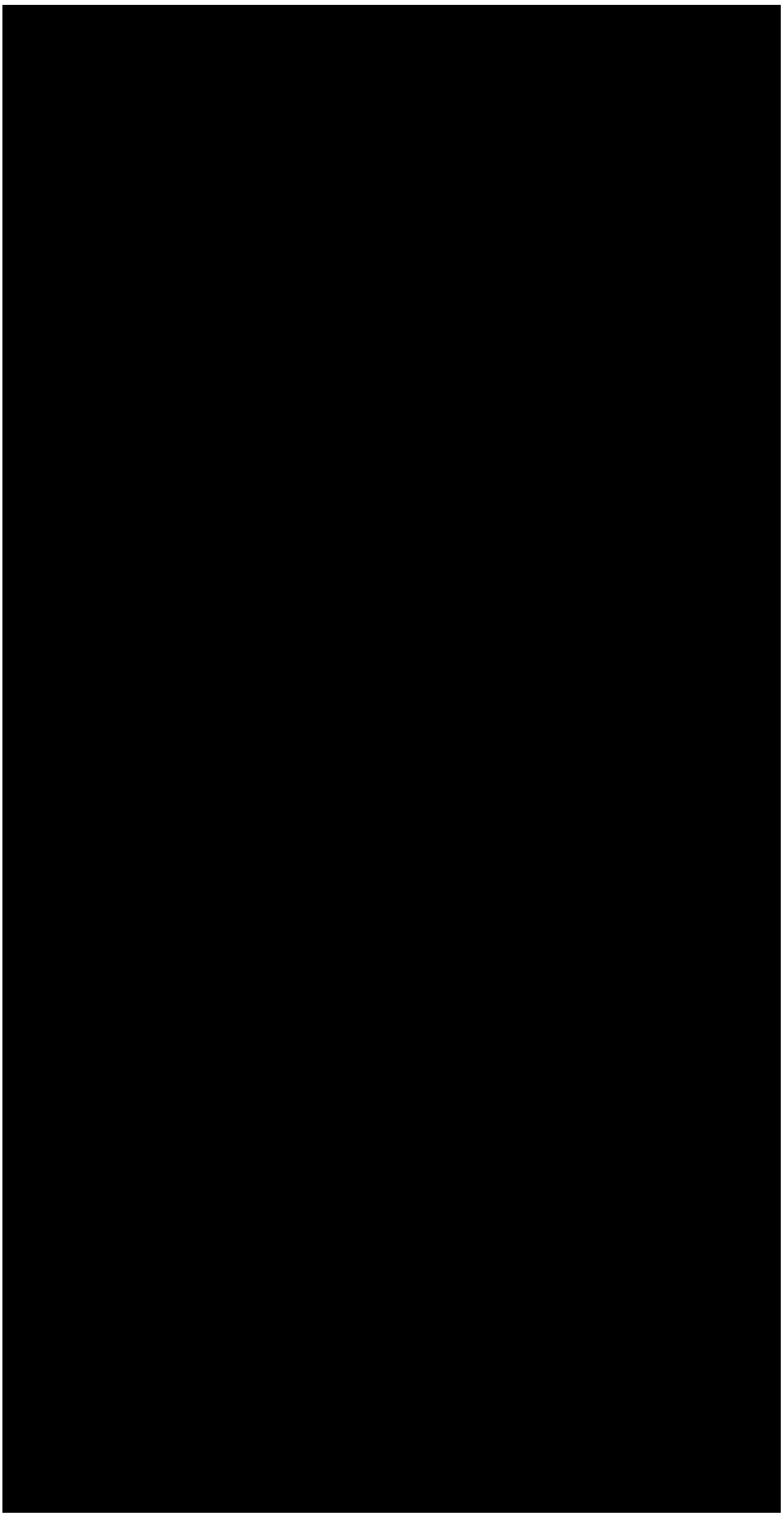

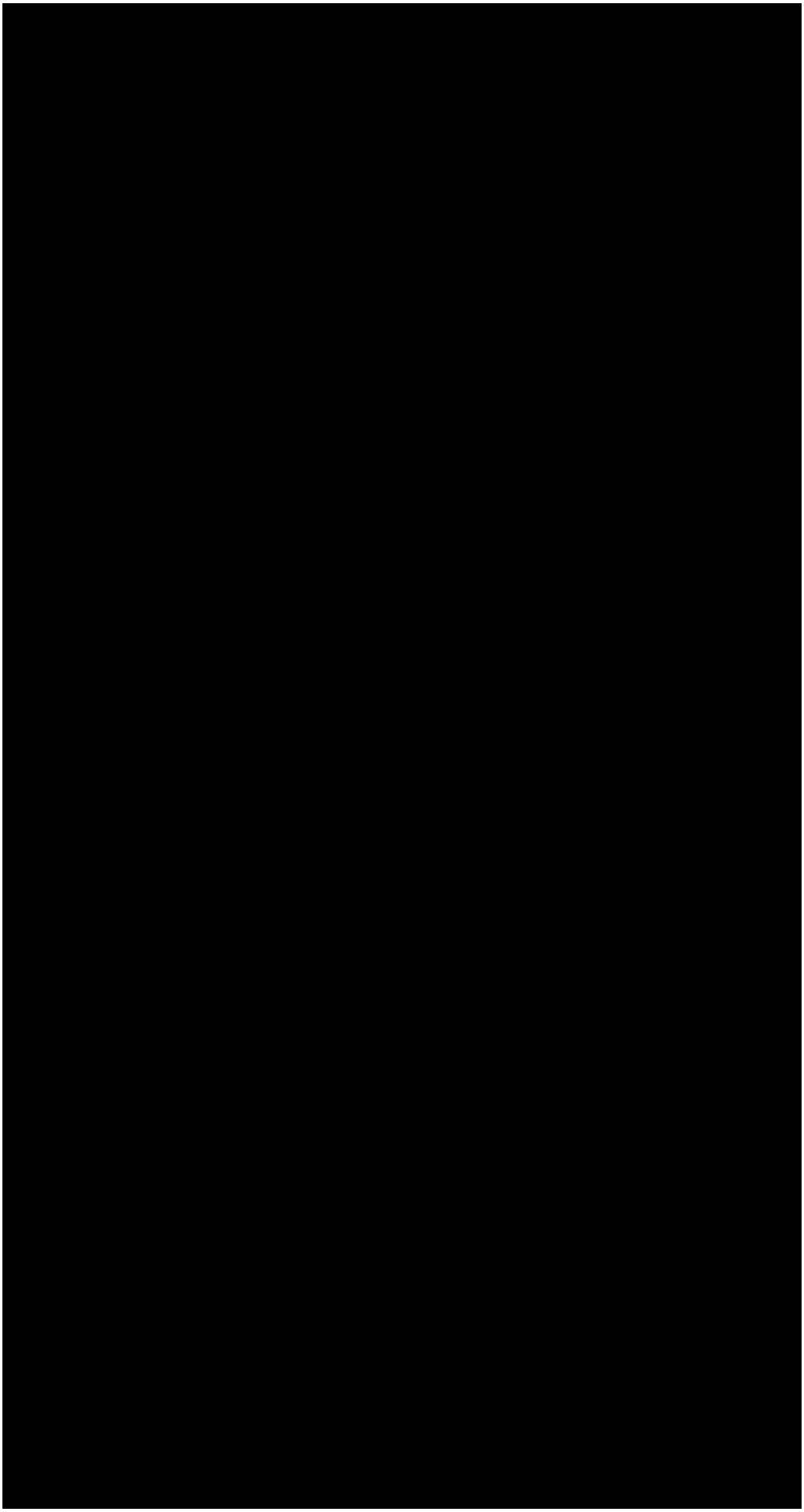

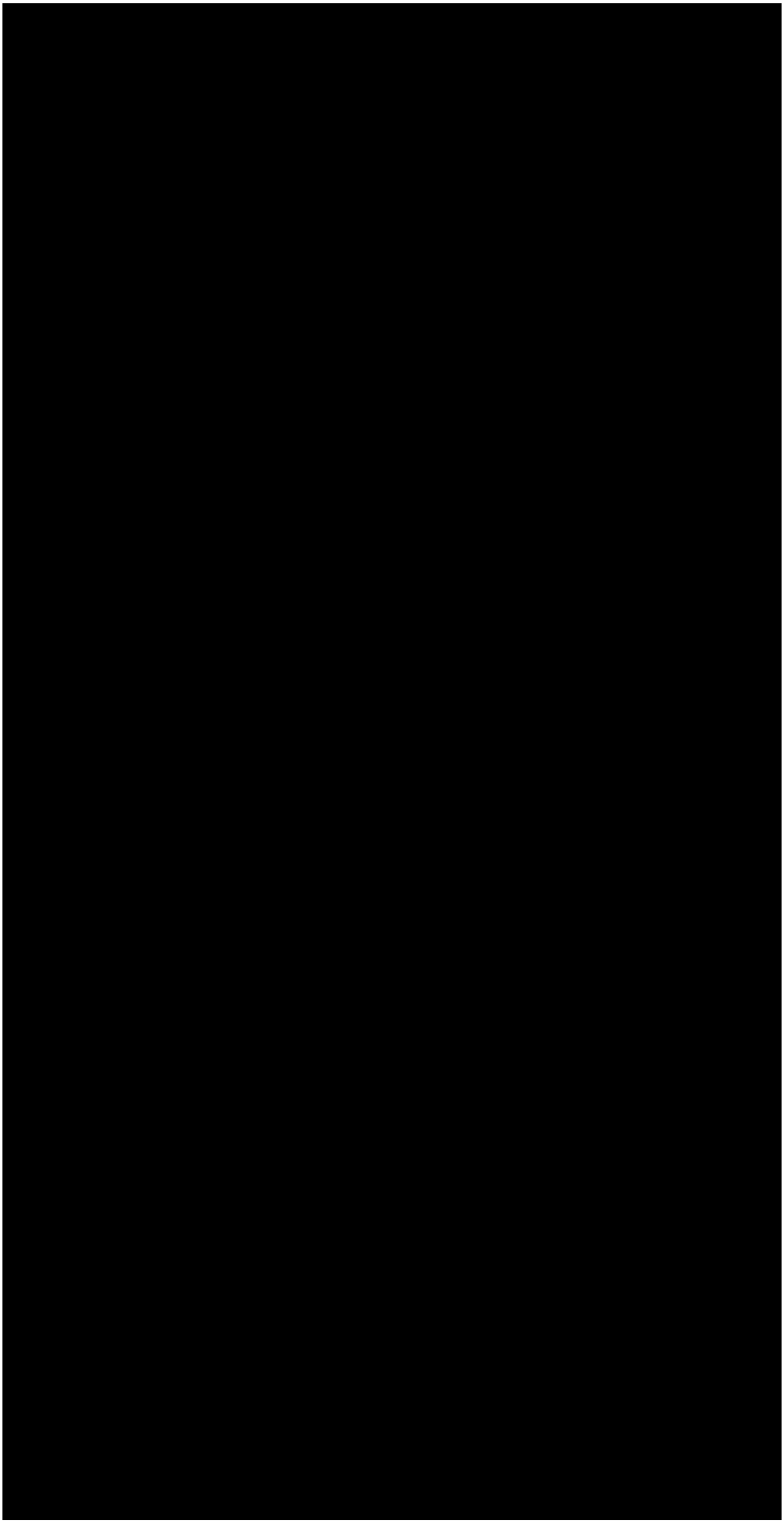

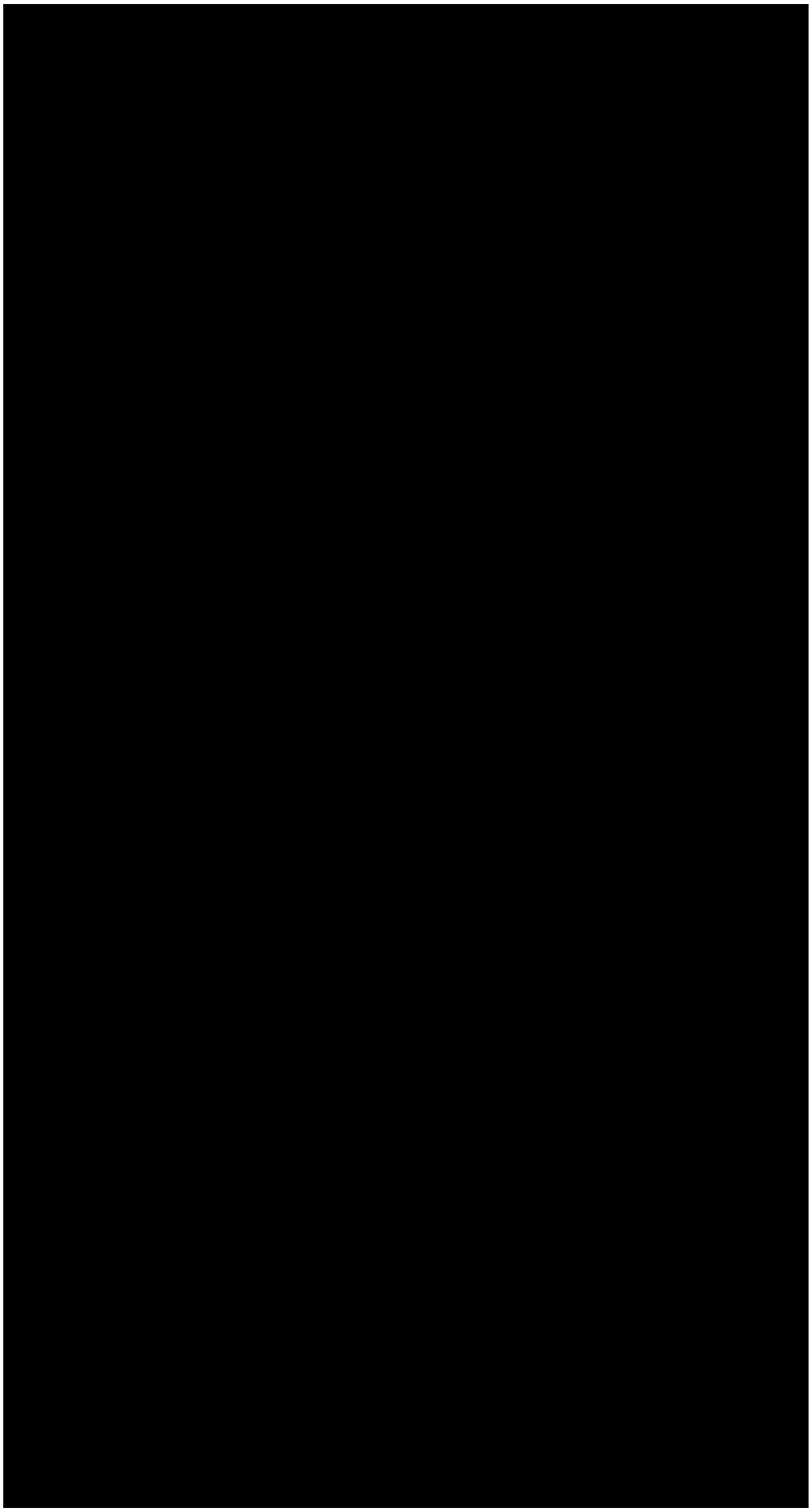

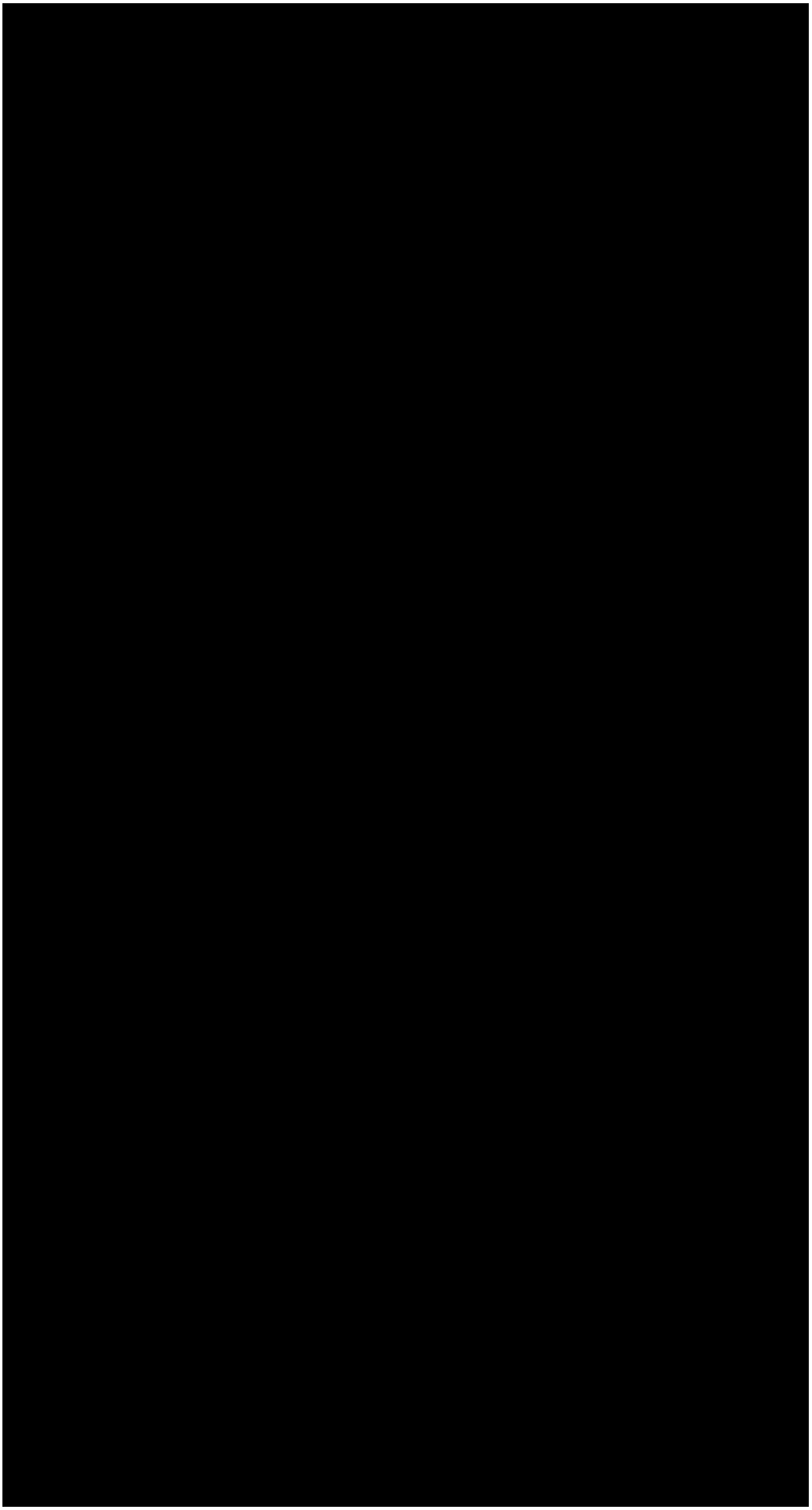

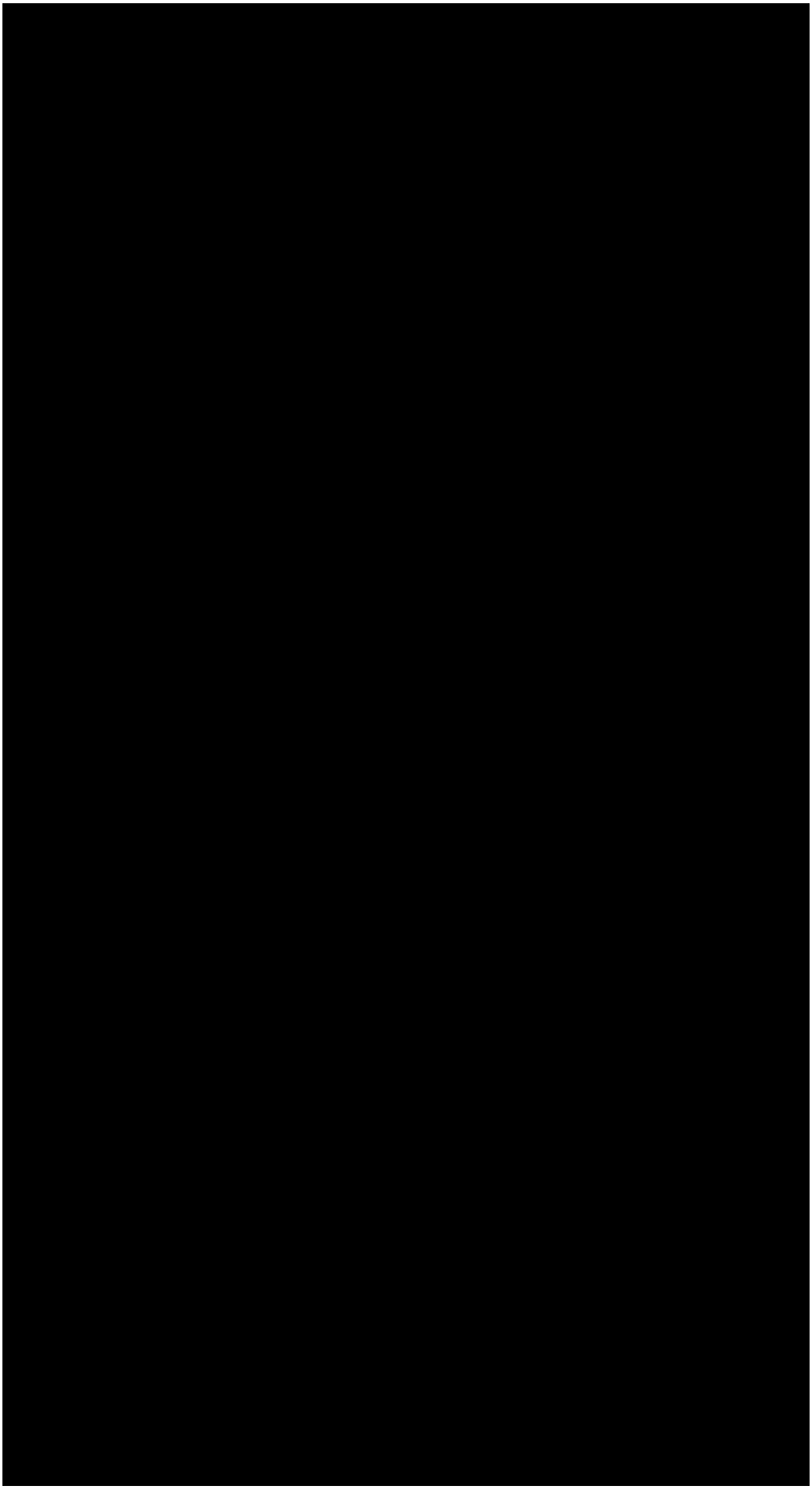

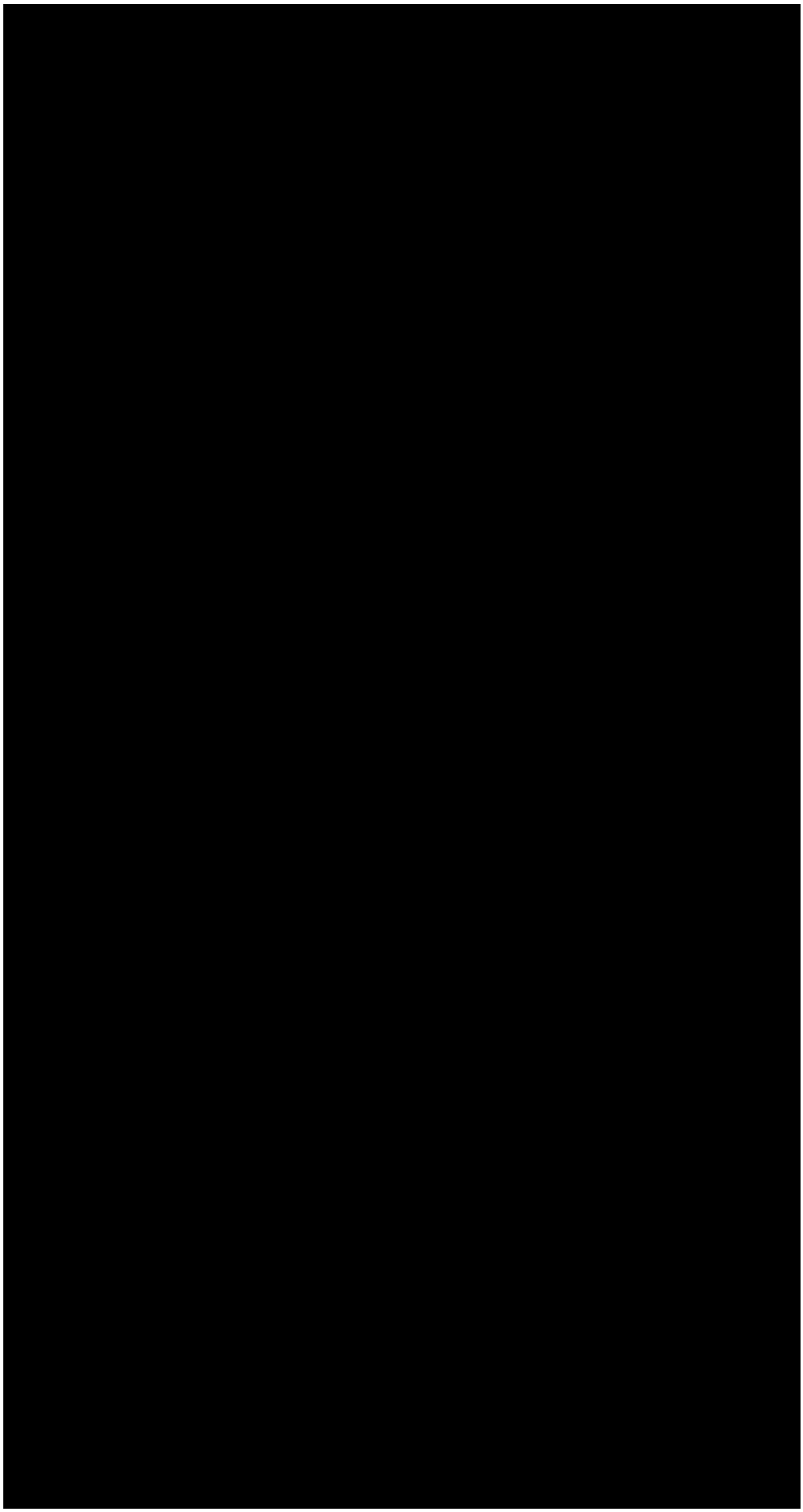

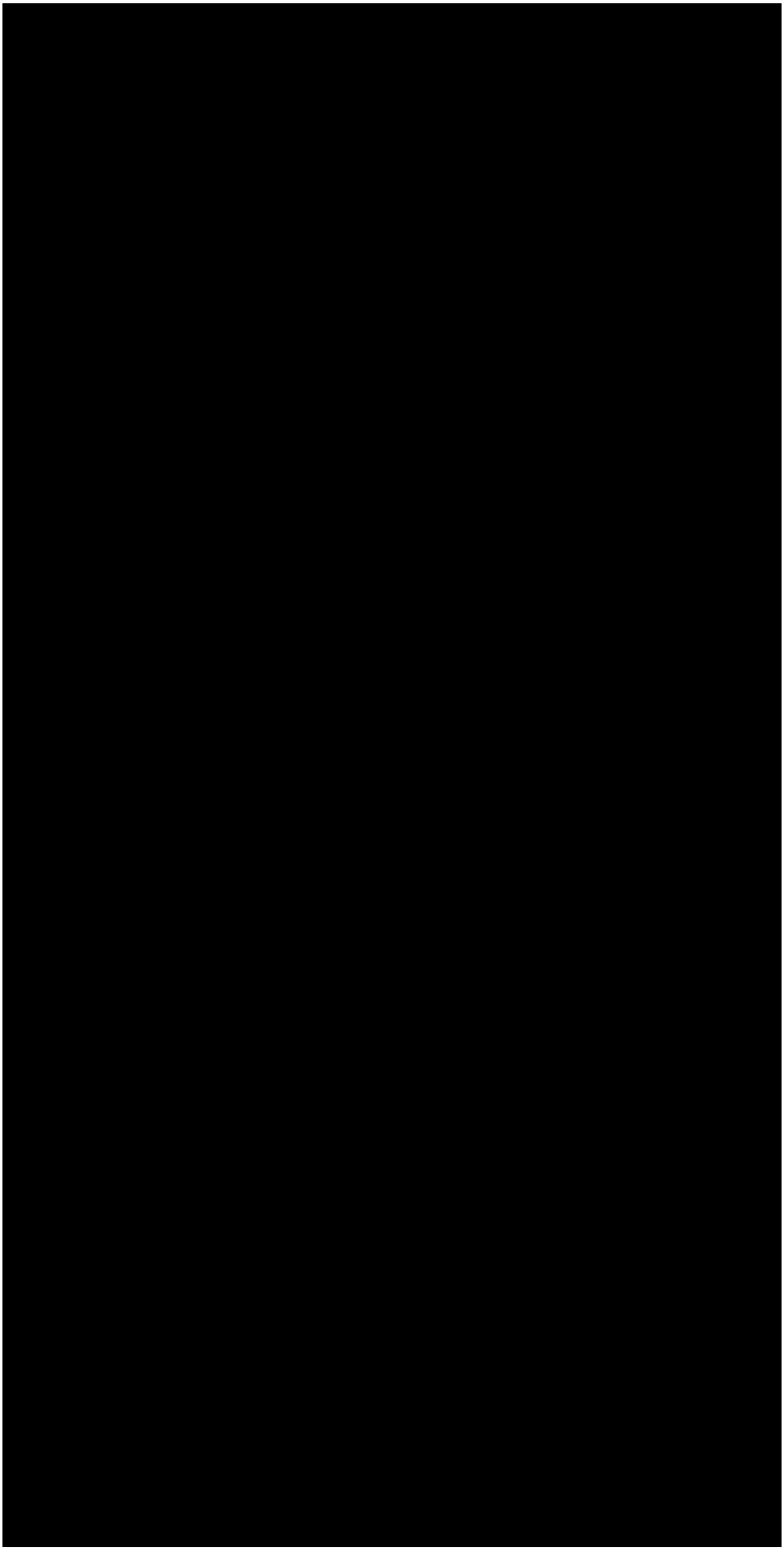

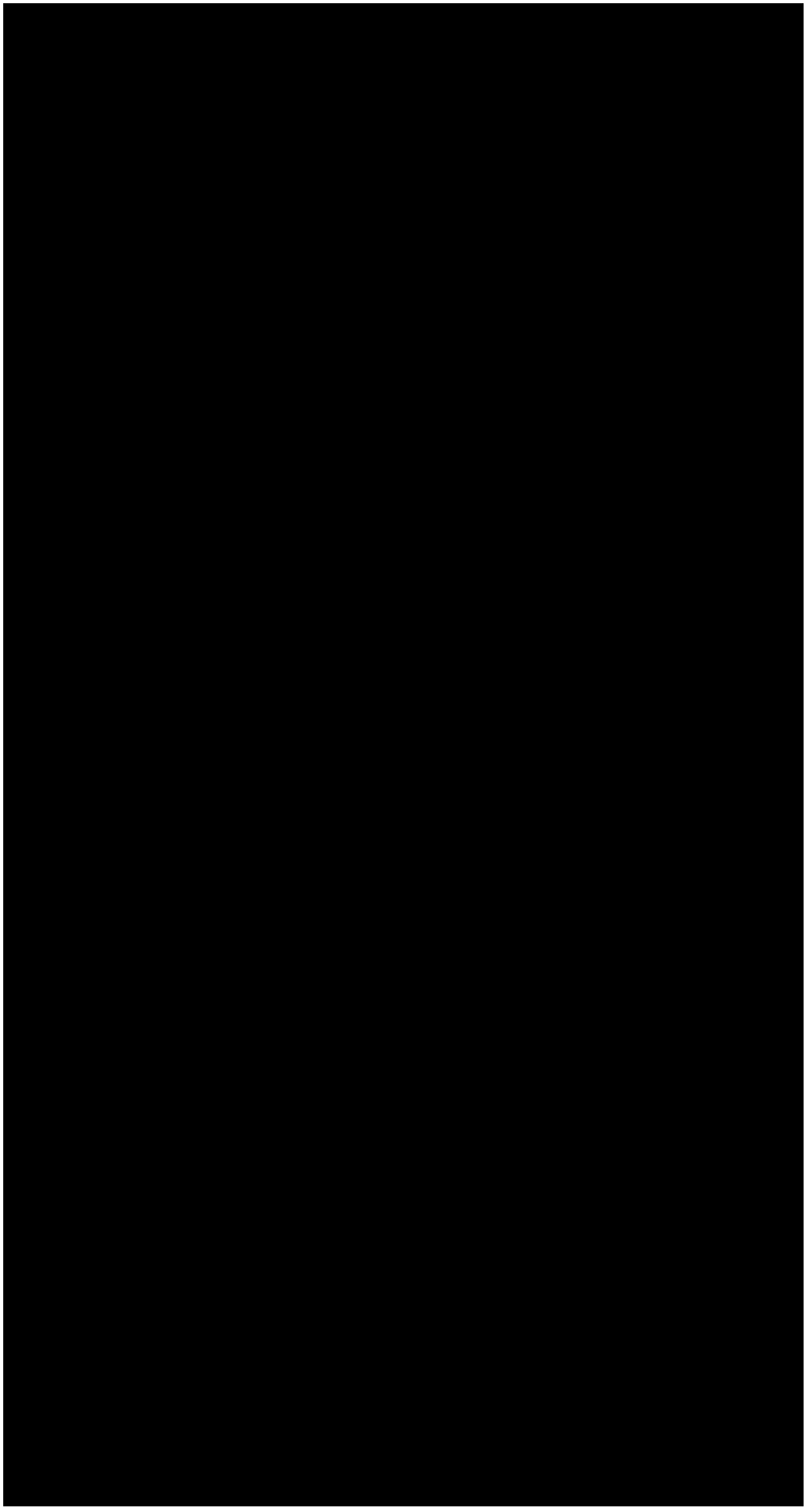

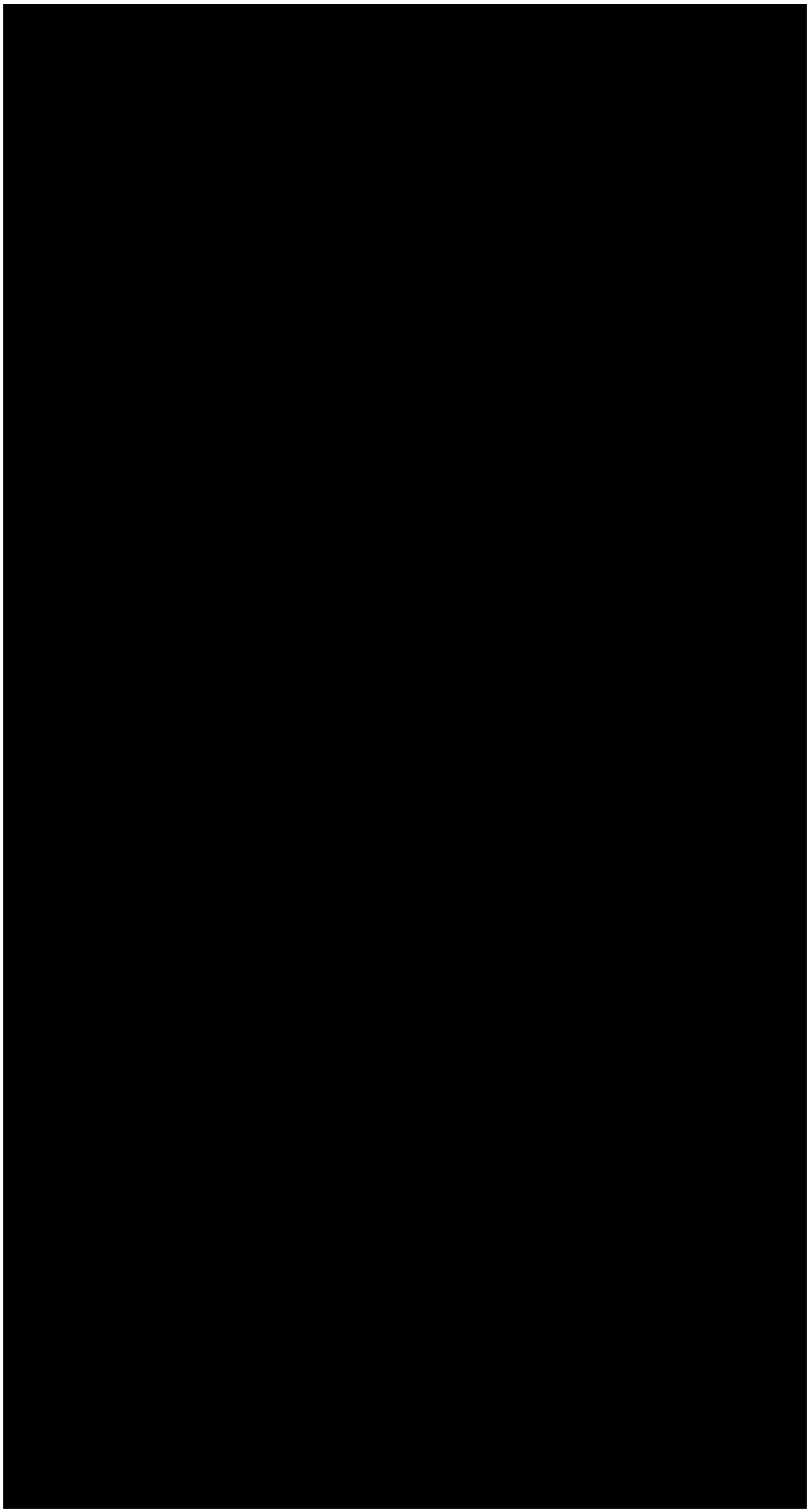

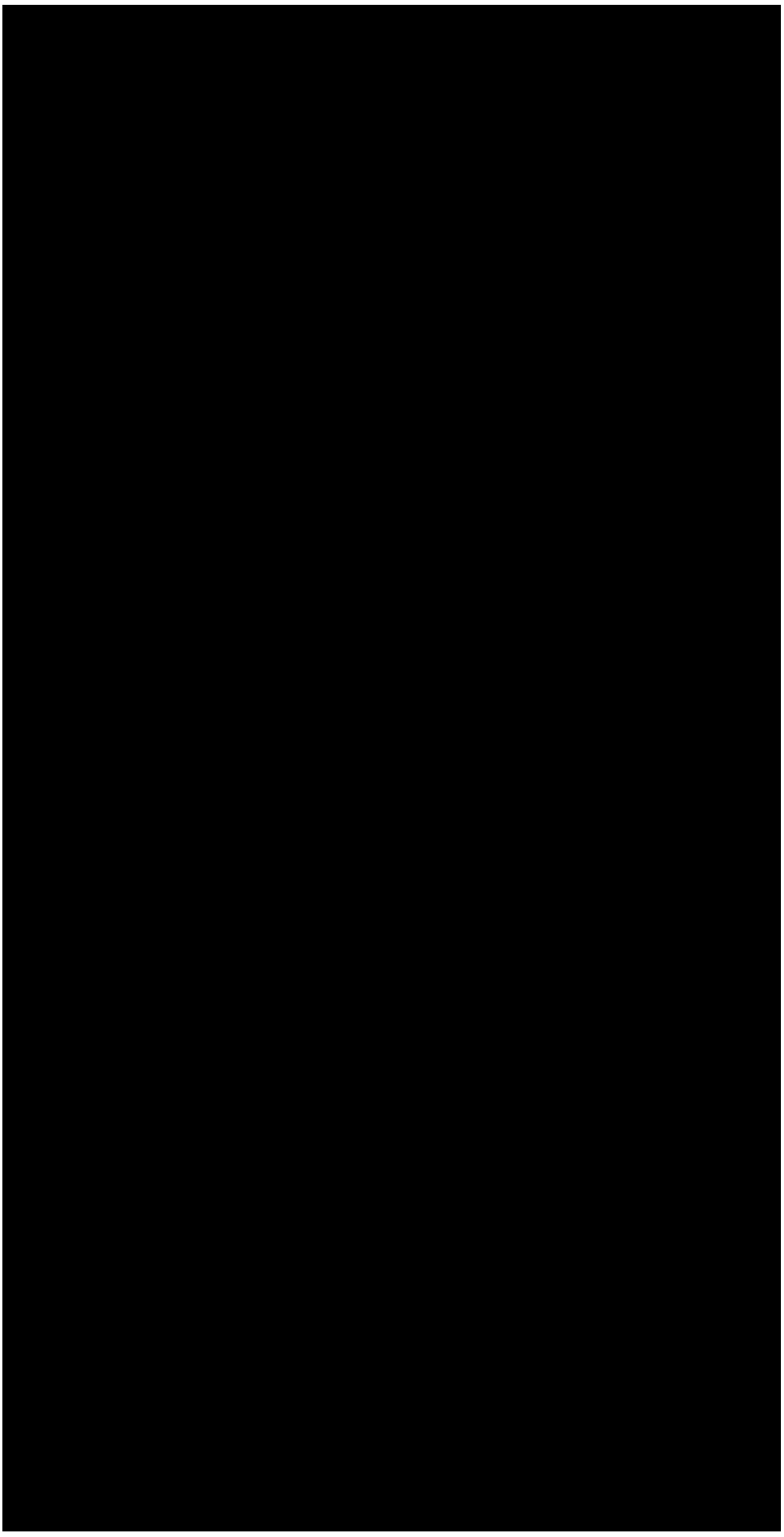

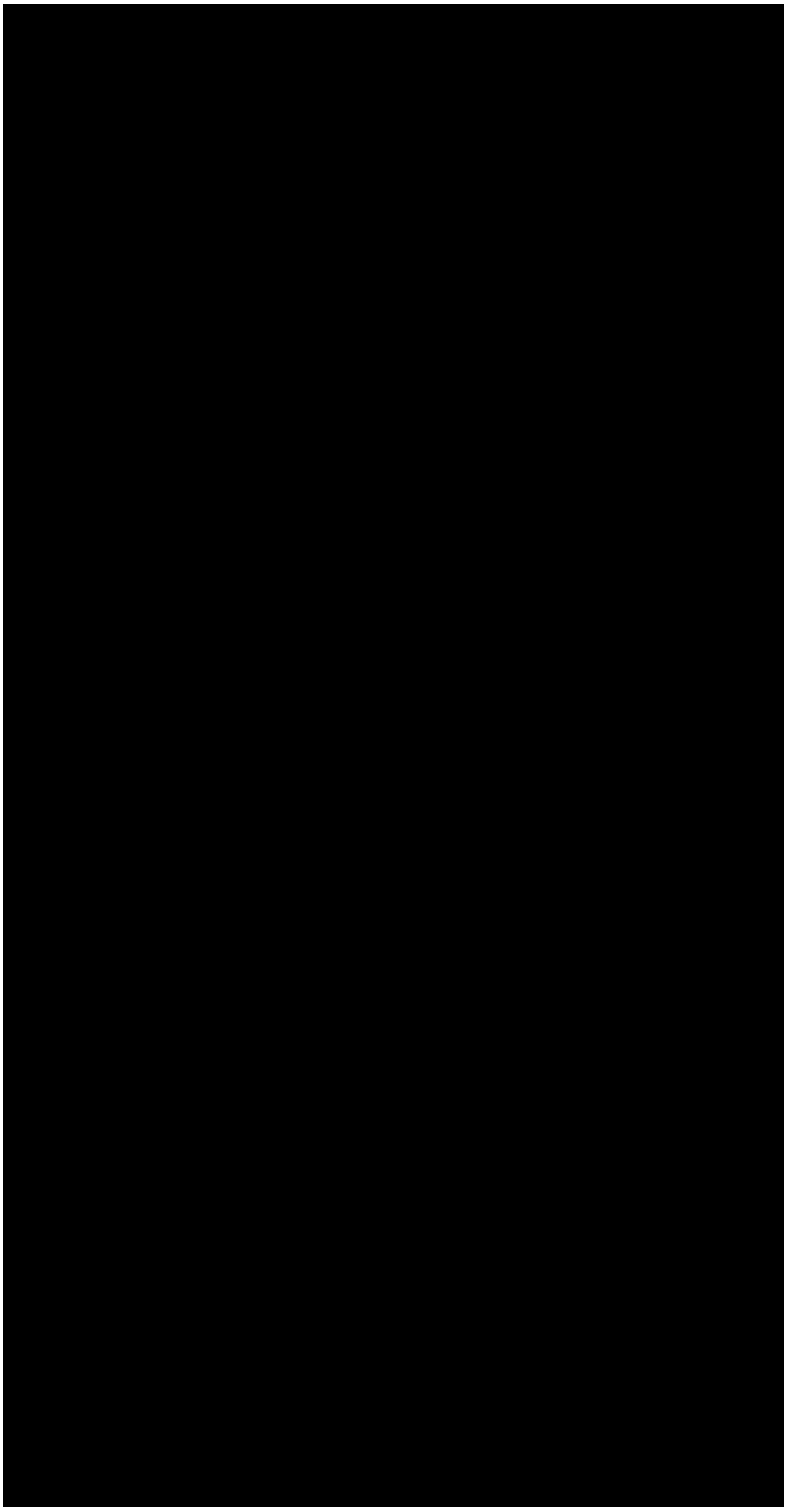

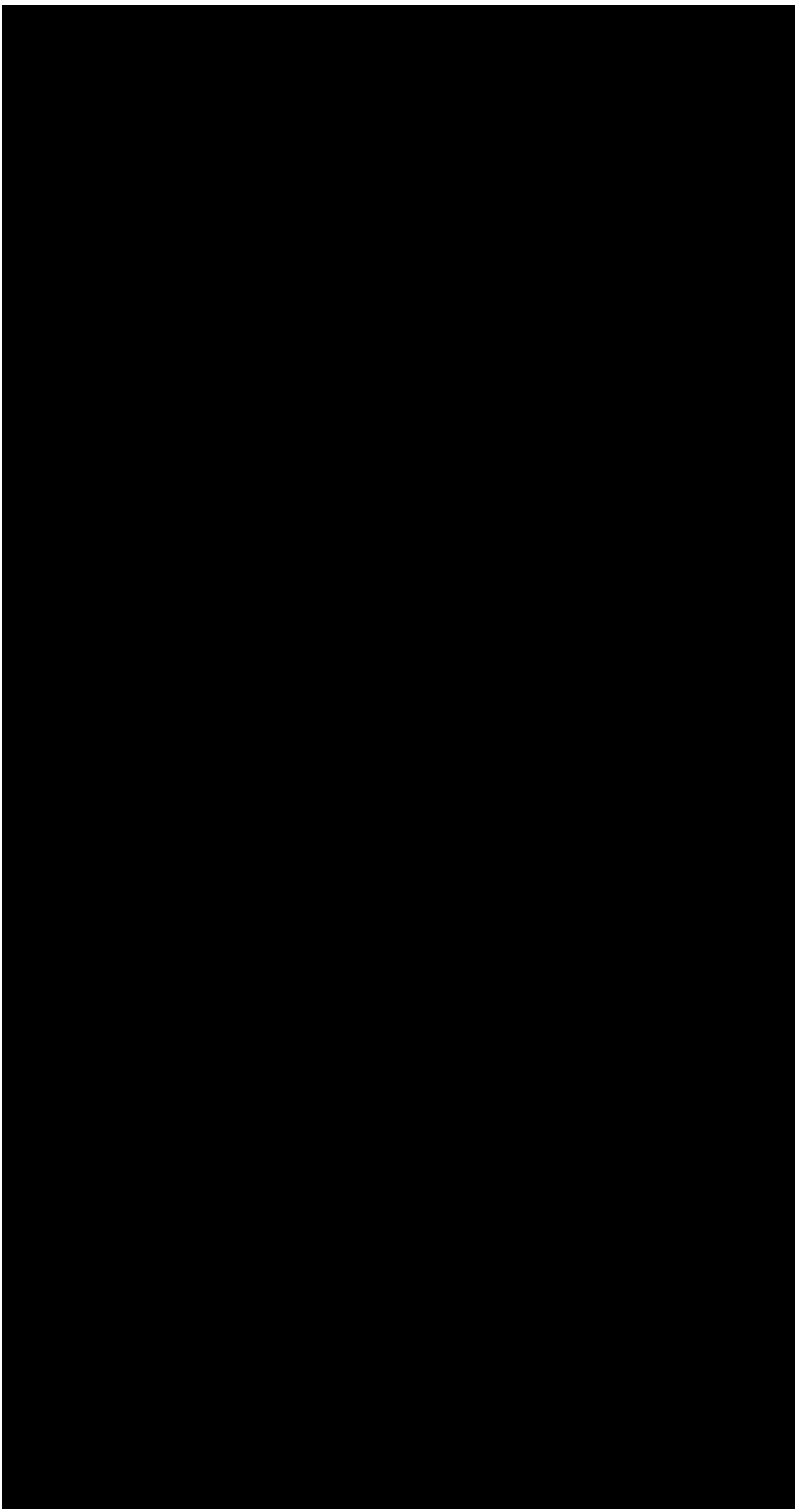

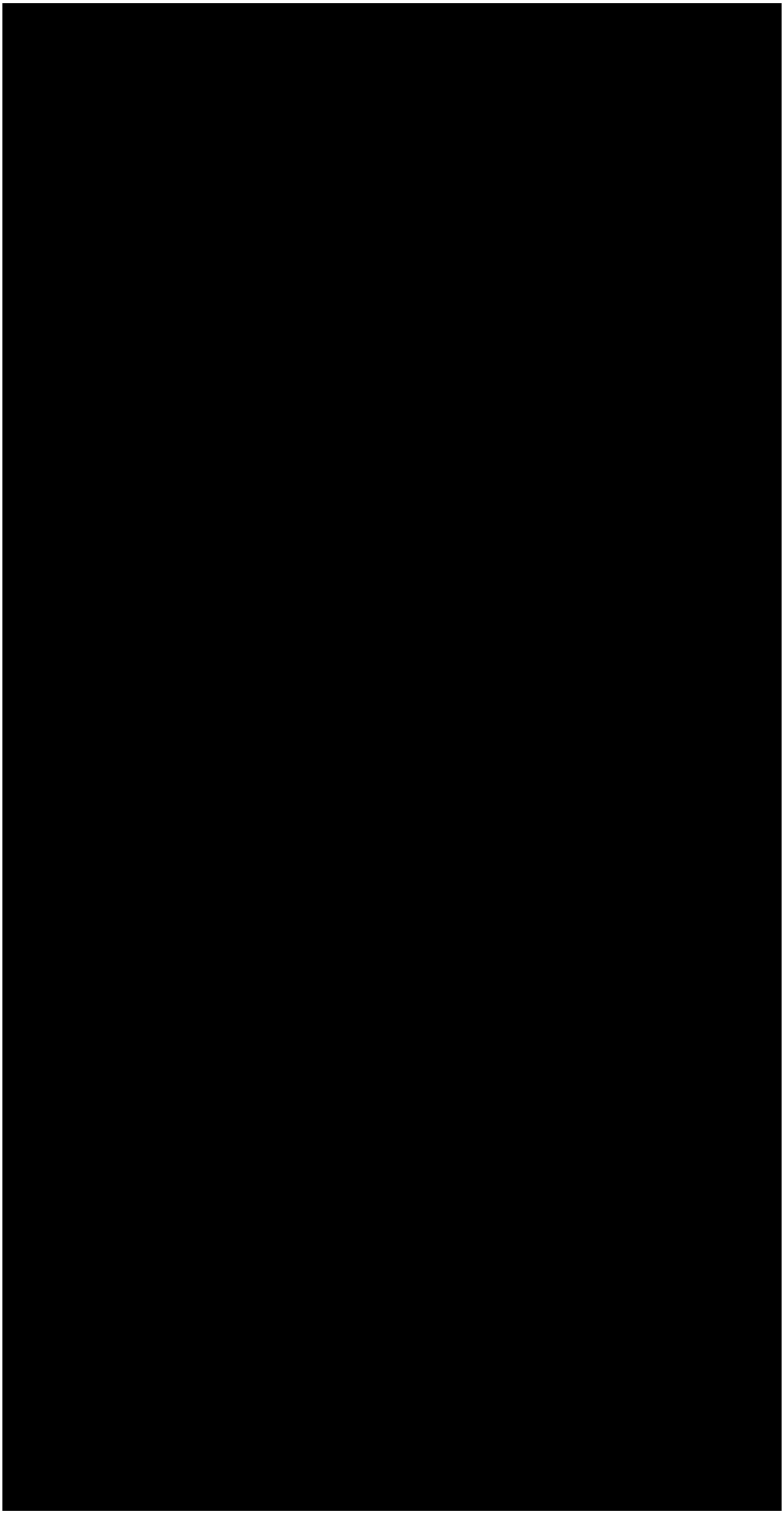

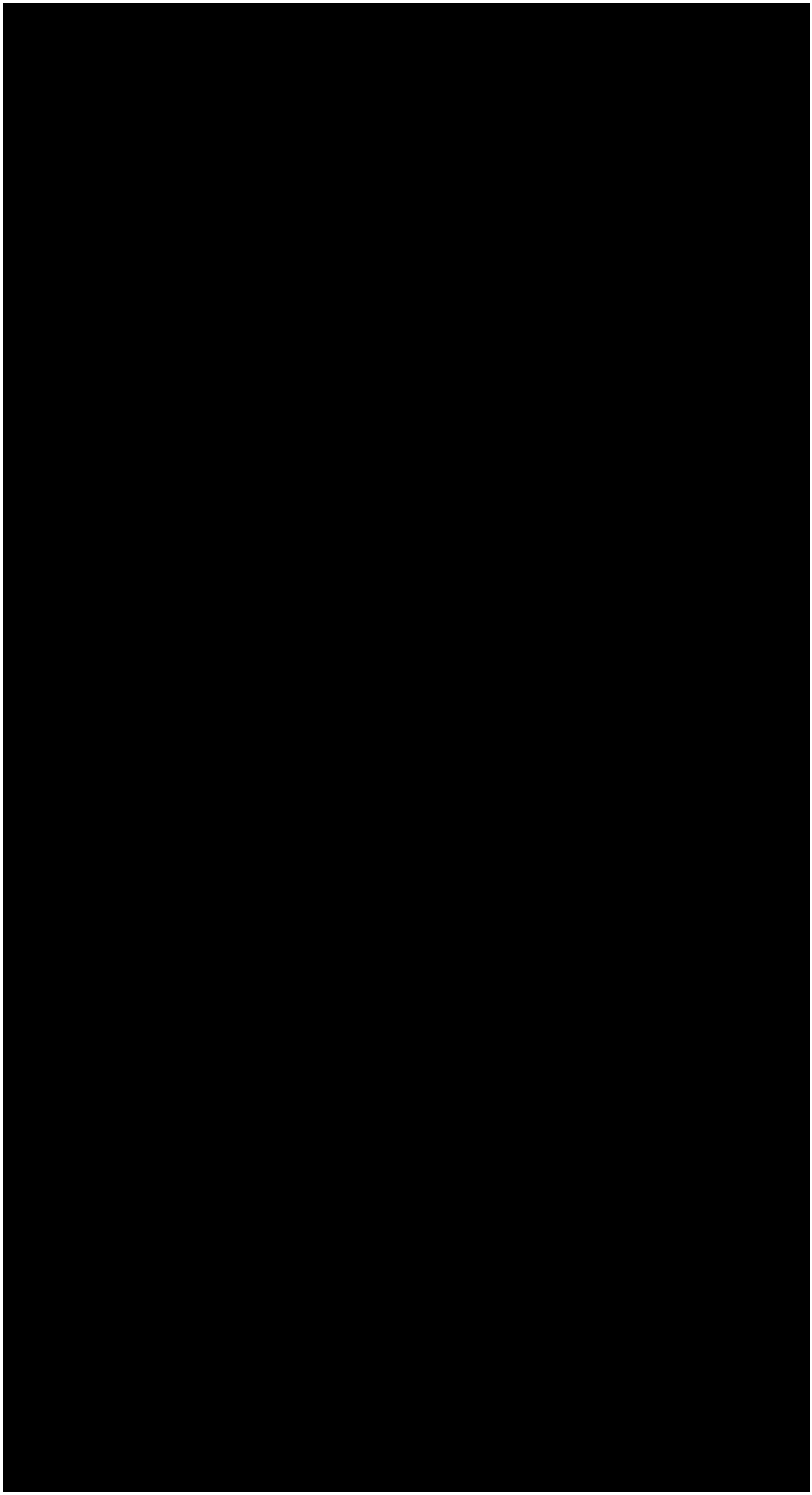

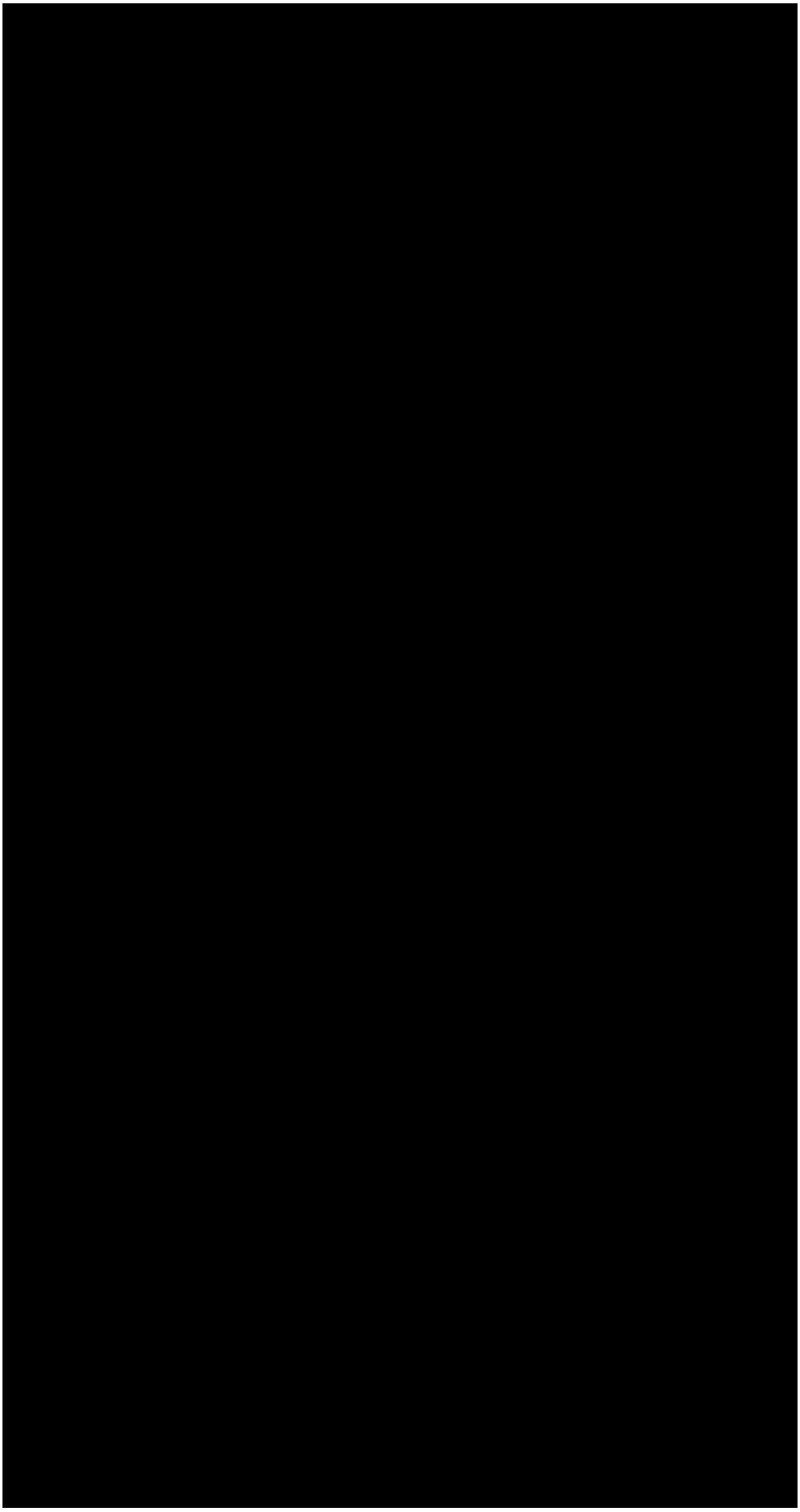

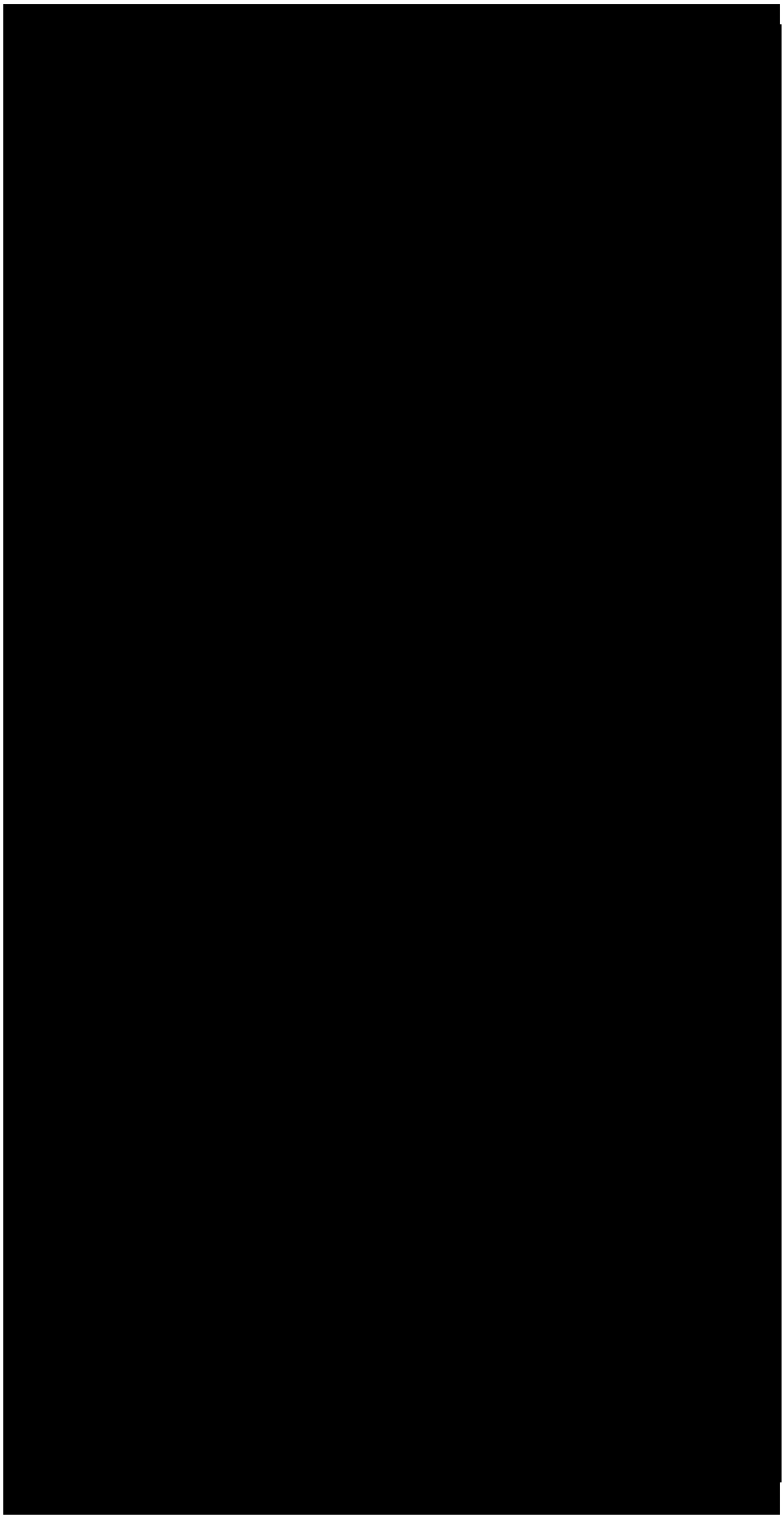

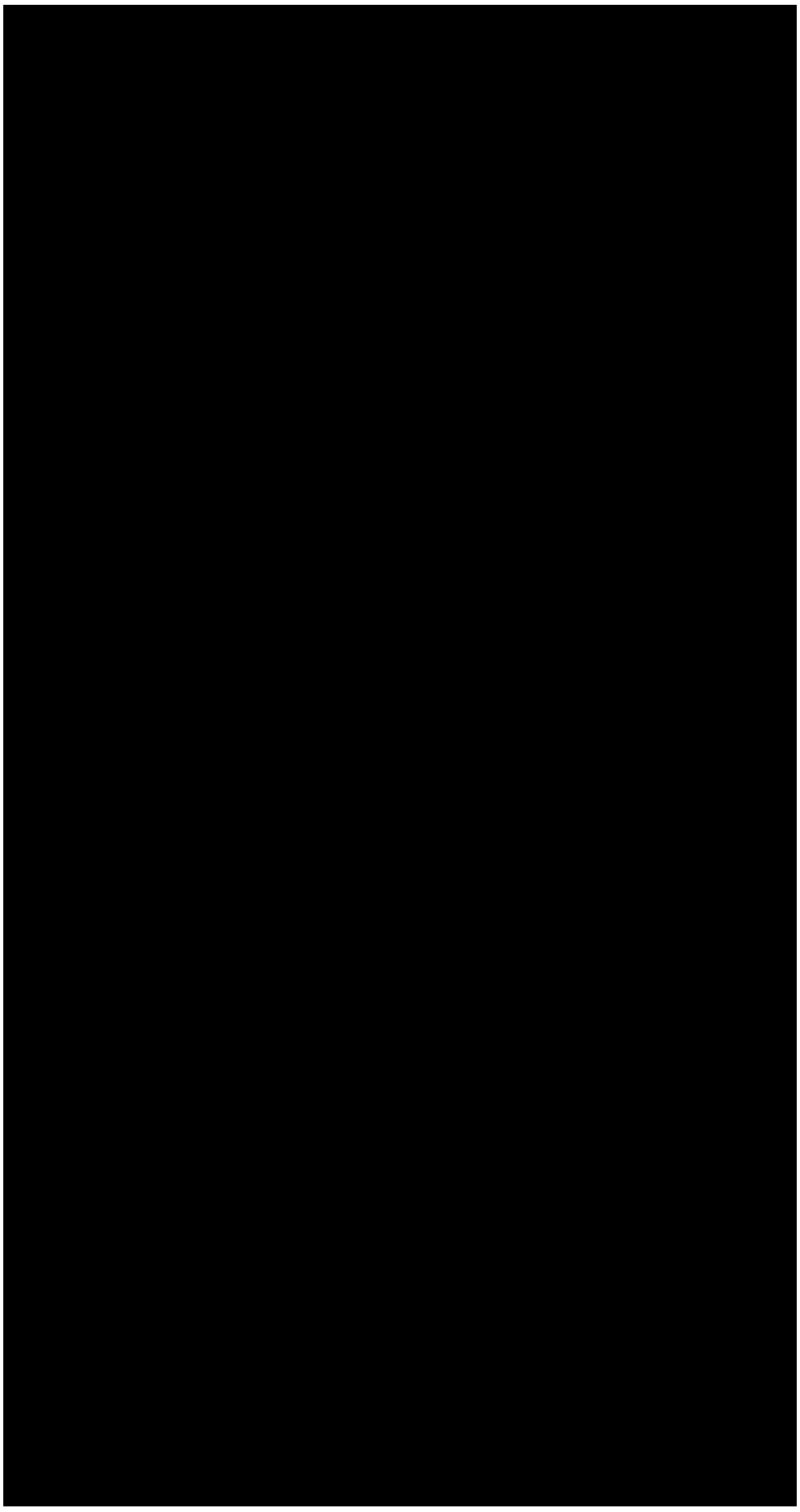

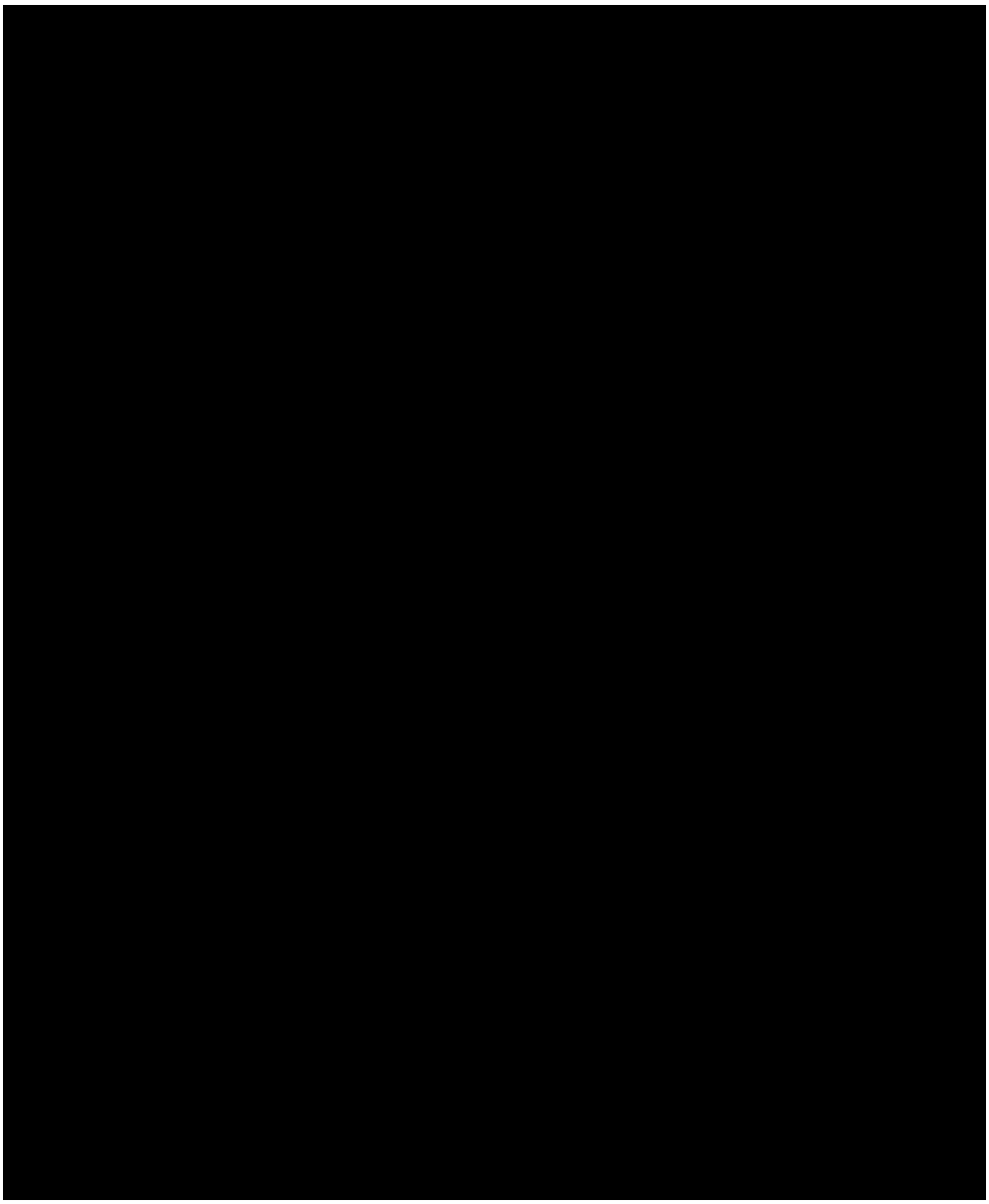

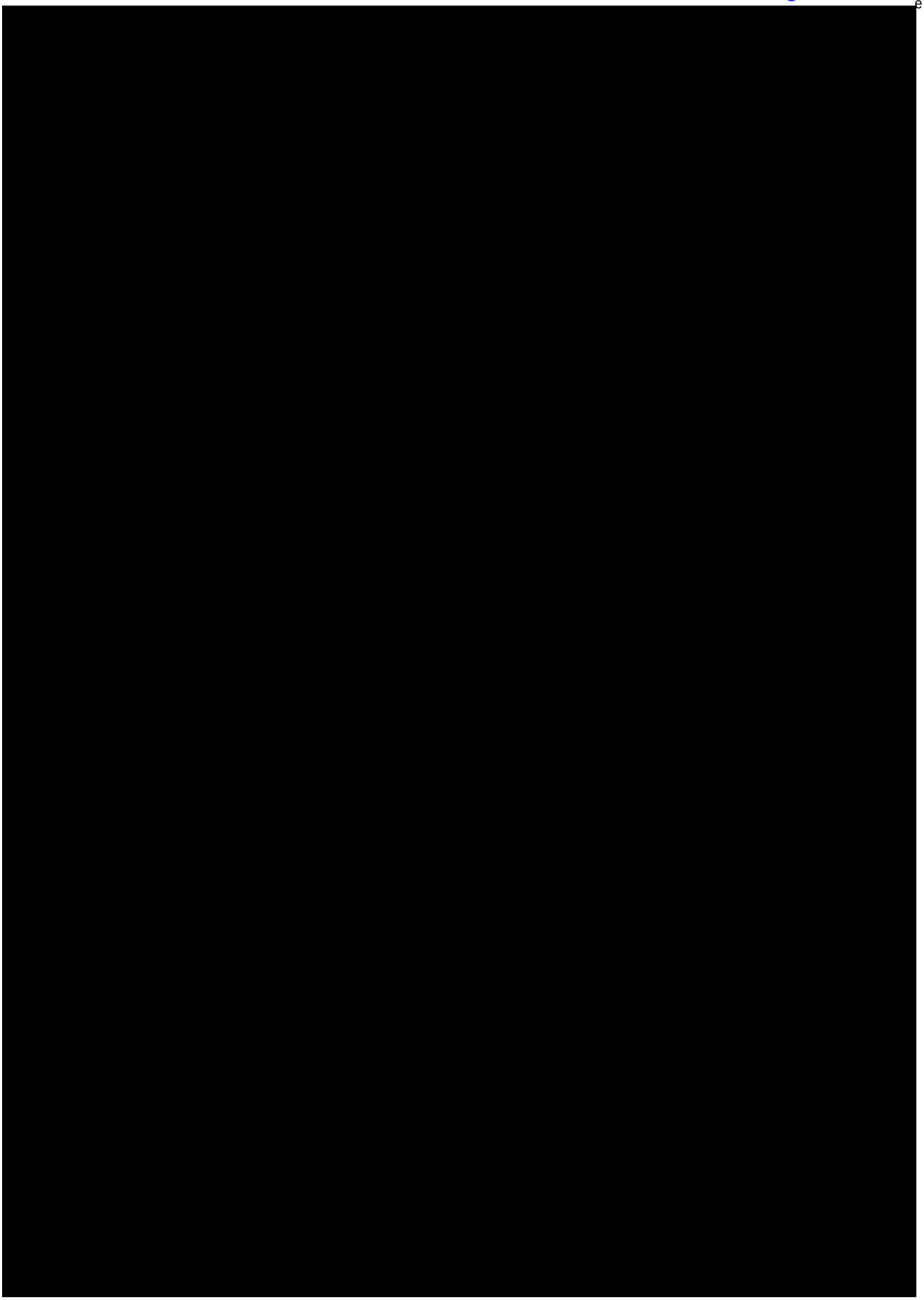

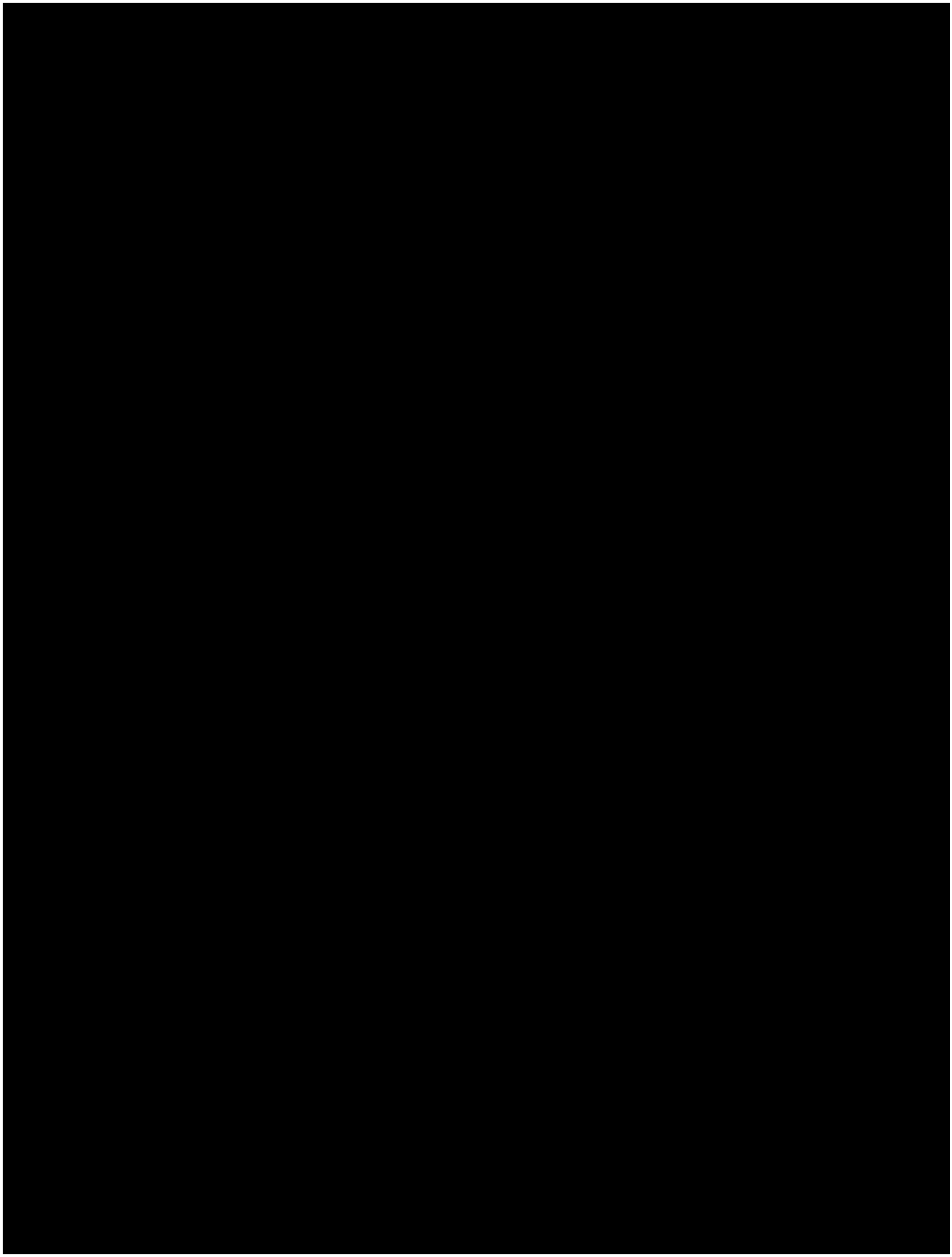

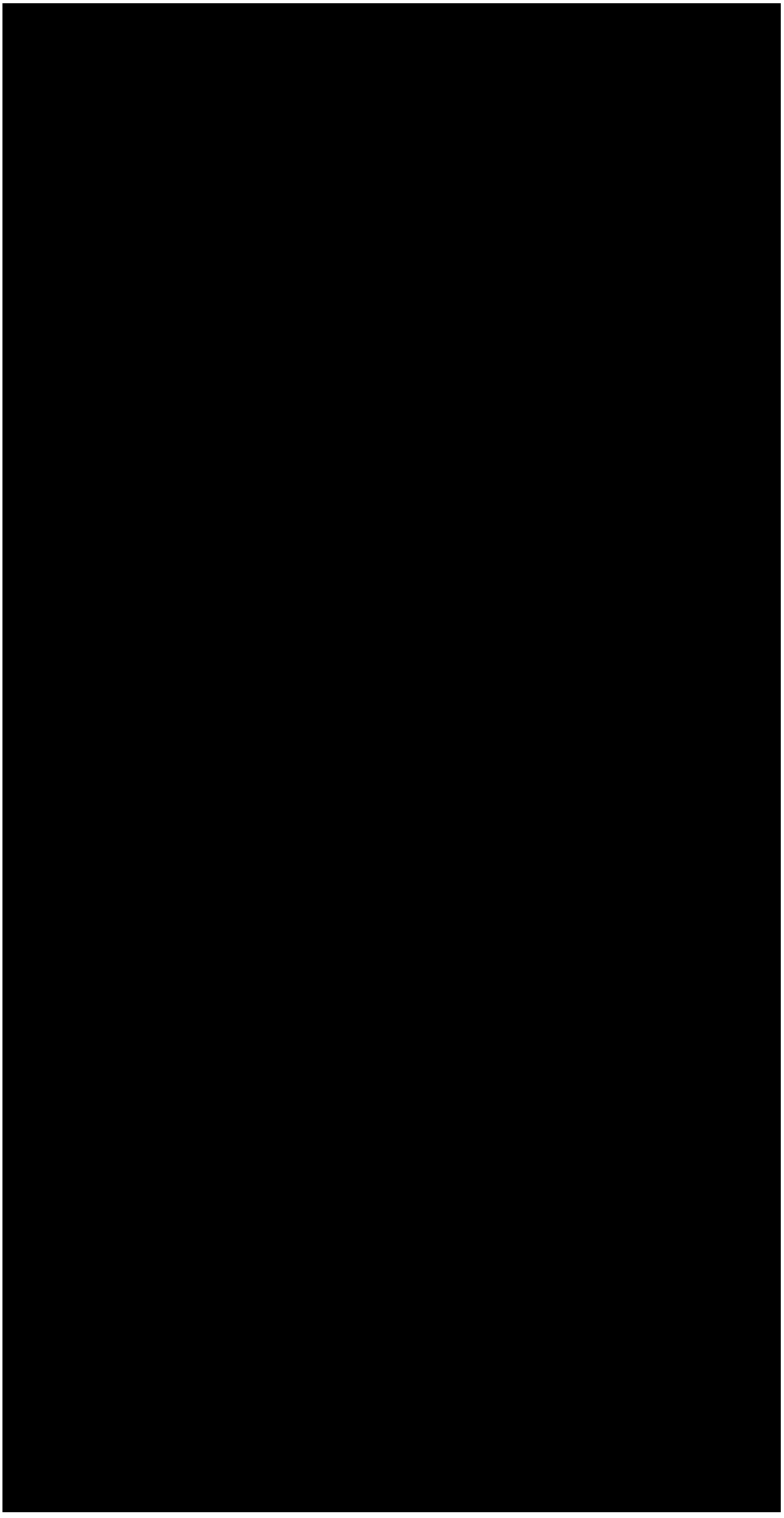

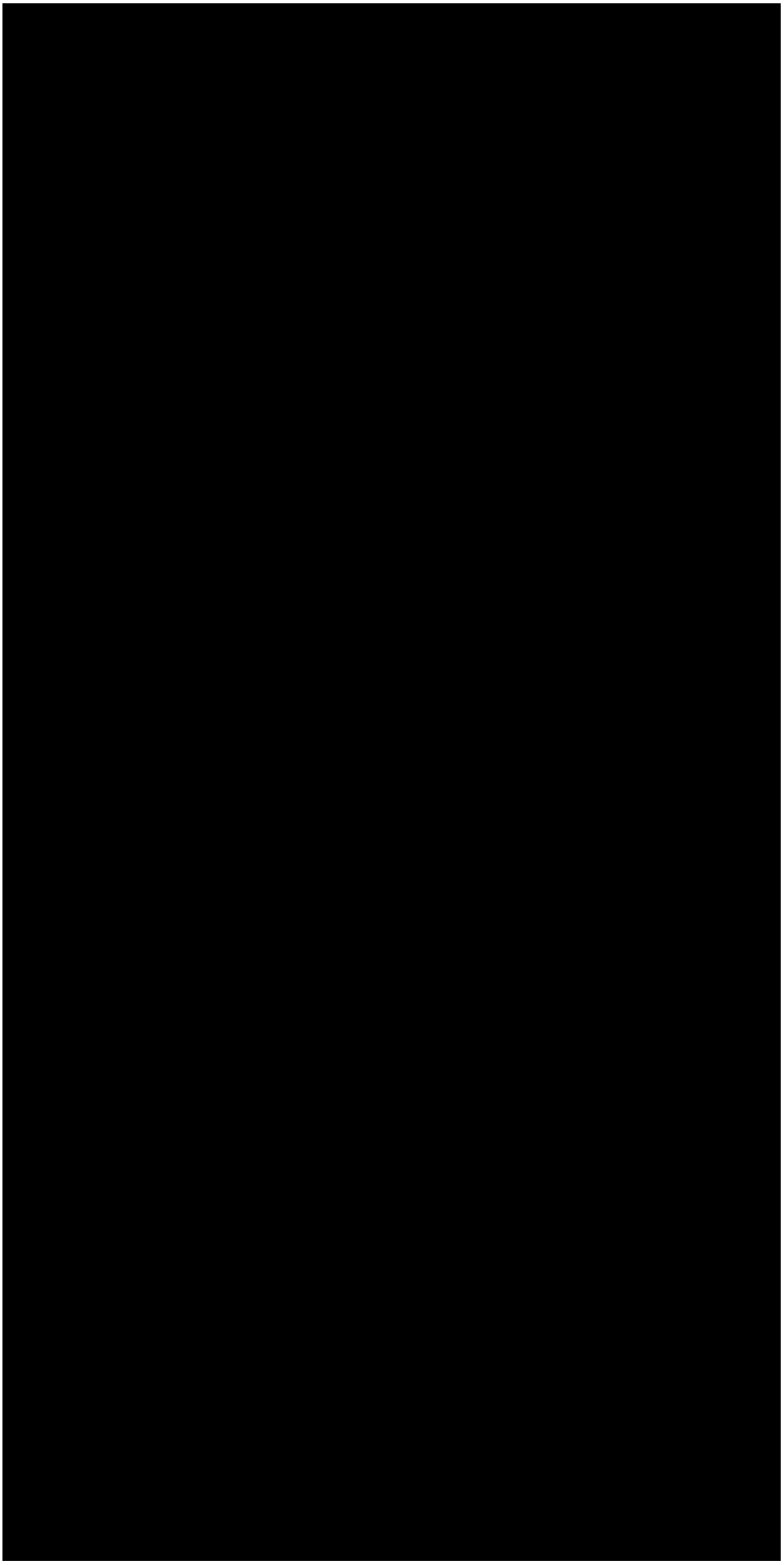

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MARYLAND PUBLIC SERVICE COMMISSION

WASHINGTON GAS LIGHT COMPANY

Case No. 9849

WASHINGTON GAS COMPANY RESPONSE
AND/OR NOTICE OF OBJECTION/UNAVAILABILITY
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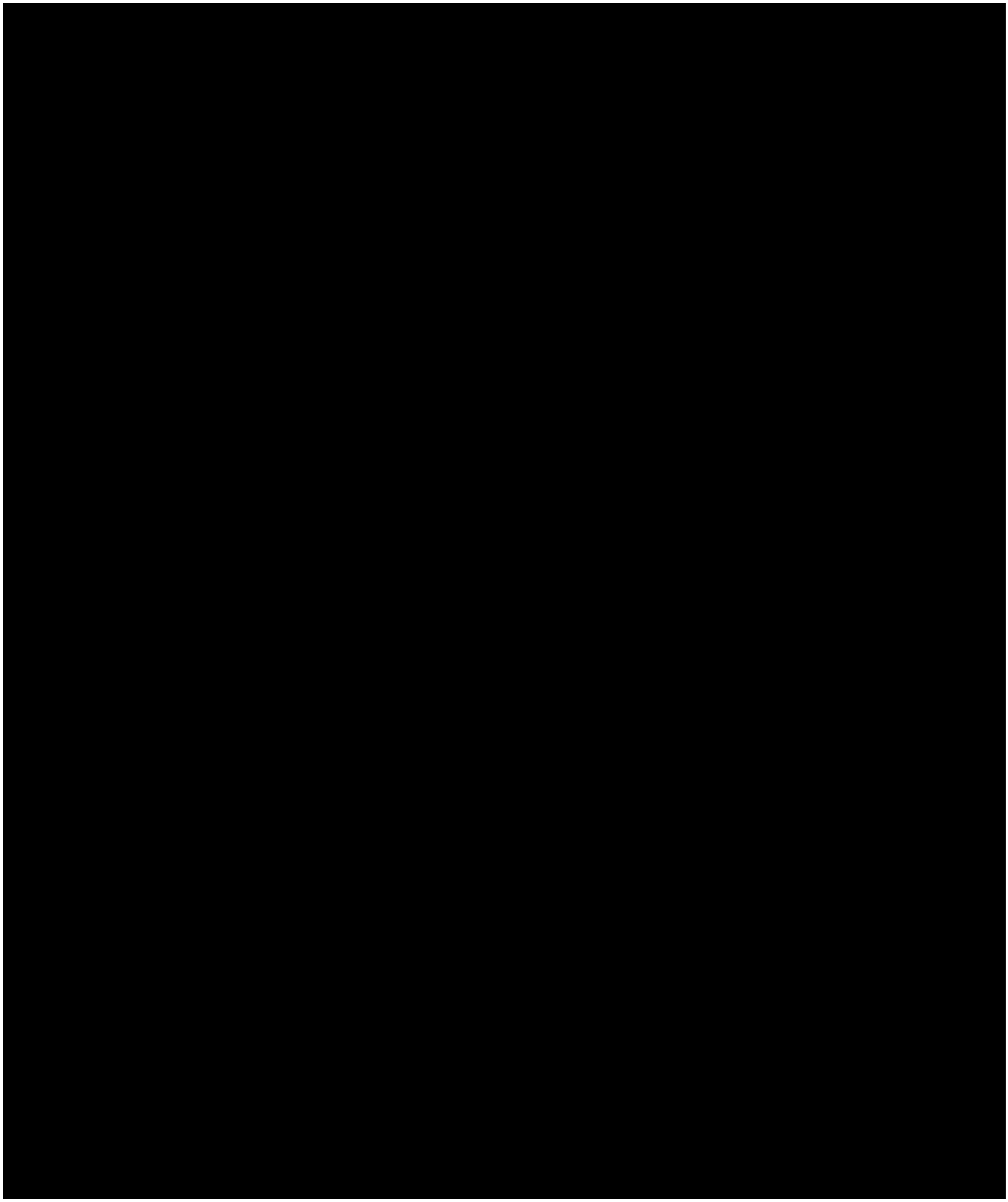

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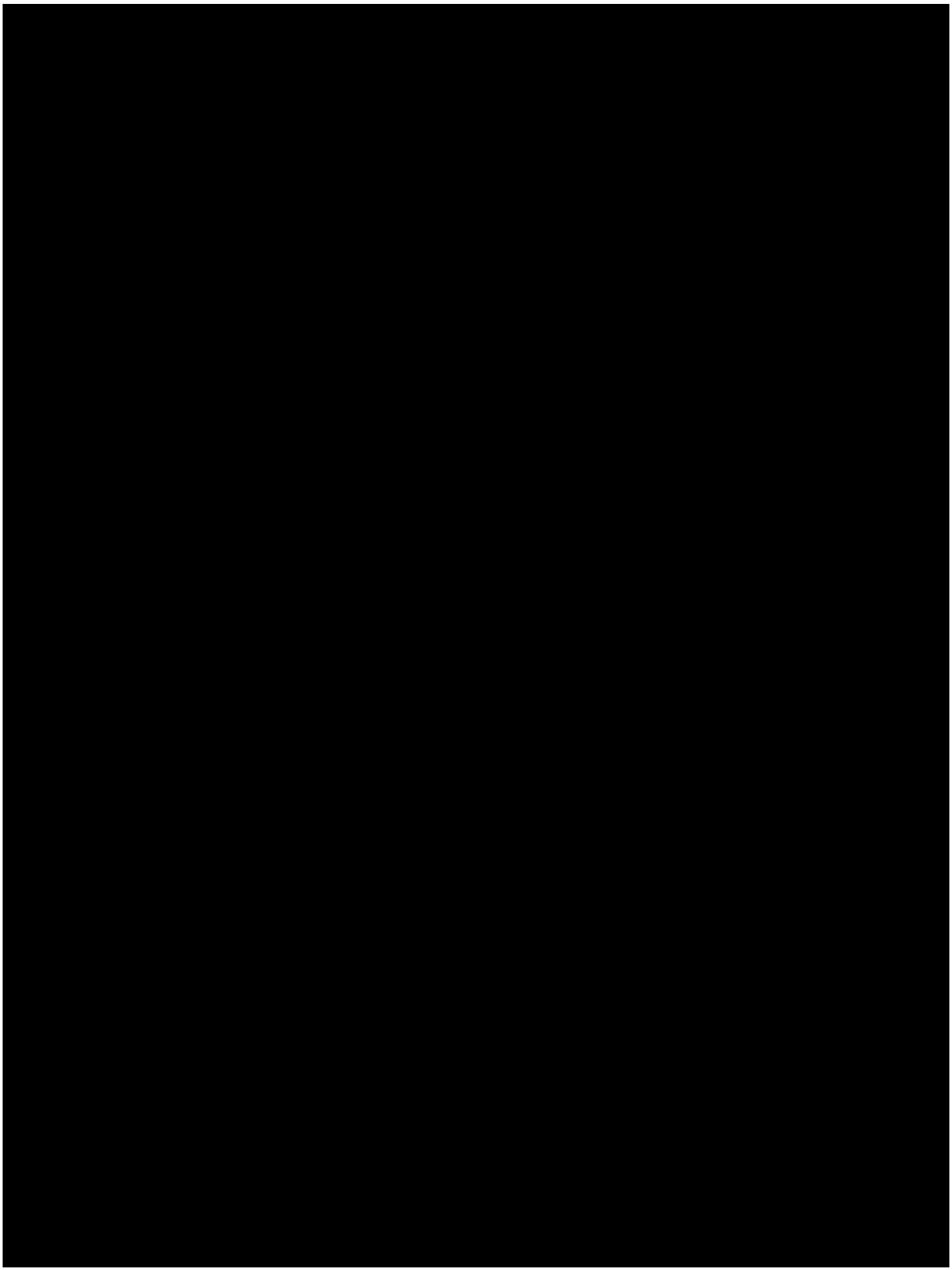

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THE PRUDENT INVESTMENT TEST IN THE 1980s

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EXECUTIVE SUMMARY

Prudence is an old regulatory concept being put to new use. The frequency of use of the concept by state utility regulatory commissions has increased greatly in the last 10 years. Under one way of counting, there were forty-two state commission cases that made significant use of the concept in the 1974-83 period and nine such cases in the 30-year period before that. The immediate occasion for most recent uses of prudence has been the turmoil in the electric utility industry: construction cost overruns in completed plants, abandonment of plants, and excess capacity.

Recent public discussions of prudence have often loosely referred to "the prudence of a nuclear power plant" or the "prudence of a cost overrun," as if an object or a cost were prudent or imprudent. In our view, prudence always relates to a decision--or the absence of a decision where one is needed--such as a decision to construct a nuclear unit, to abandon a coal unit, or to use certain construction management practices.

For a state commission judging the prudence of a utility investment decision, it is useful to understand the concept of a prudent investment decision not only in public utility law, but also in related areas of law and in finance and management science. Investment decision rules in finance and management science determine a generally accepted mode of behavior for managers making large capital investment decisions in any industry. For competitive companies, investment decisions are intended to maximize profits for investors. All financial authorities agree that the best way to determine whether a capital investment in a project is prudent from the stockholders' point of view is on the basis of the discounted after-tax cash flows to be expected. For an unregulated company, investment decisions are simply a matter of calculating such cash flows.

For a regulated utility, investment decisions must also take into account the franchise obligations to provide all the service demanded, to ensure adequate and reliable service, and to provide service at a reasonable price. Utility decision makers evaluating probable future cash flows must assess the probable regulatory treatment of their investment decisions, a treatment now frequently determined on the basis of prudence.

The concept of prudence is used throughout the law as a standard of conduct owed to others. It seems likely that the concept of prudence in public utility law was borrowed from other areas of law that use the concept. The "prudent man" concept is well known as a standard of care expected in avoiding injury to another person or damage to his property. Other areas of law use the concept of prudence as a standard of care in the conduct of business, particularly where the economic use of property is involved and a legal duty of care is owed to other persons. Here the legal obligations are analogous to the obligations of public utilities for prudent investment decisions. These include the legal obligations associated with mineral development leases and trust and estate management. In these areas of law, the concept of prudence protects the rights of individuals not in control of investment decision making. It does not require

perfection in decision making but does require, for example, avoidance of deliberate exposure to substantial risk where the individuals not in control could suffer financially.

The concept of a prudent investment in public utility law is a regulatory oversight standard that attempts to serve as a legal basis for judging whether utilities meet their public interest obligations. It was used as early as 1914 by the public service commission in Massachusetts. The concept first achieved wide recognition in public utility law after it was used by U.S. Supreme Court Justice Brandeis in a concurring opinion in 1923. Brandeis introduced the concept of a prudent investment as a rate base valuation method in an ongoing constitutional debate about utility valuation. While the prudence method did not achieve the status of the only constitutionally correct valuation method, it became a judicially developed concept useful for determining what facility costs should be allowed in rate base. Federal and state legislation rarely apply the concept of prudence explicitly to public utilities. A notable exception is the recent Congressional consideration of prudence as a regulatory standard governing the natural gas acquisition practices of interstate pipelines. However, the concept of a prudent utility decision has been abstractly articulated by the courts, leaving broad discretion for the application of the prudent investment standard by state commissions.

Review of the many recent state commission applications of the standard suggests four guidelines for successful use of the prudent investment test. These are, first, that there should exist a presumption that the investment decisions of utilities are prudent. The presumption of prudence can be overcome, however, by an allegation of imprudence that is backed up by substantive evidence creating a serious doubt about the prudence of the investment decision. Once the presumption of prudence is overcome, a commission needs to decide on the legal standard for judging prudence. The second guideline is to use the standard of reasonableness under the circumstances. That is, to be prudent, a utility decision must have been reasonable under the circumstances that were known or could have been known at the time the decision was made. A corollary to the standard of reasonableness under the circumstance is a proscription against the use of hindsight in determining prudence. Observing this proscription is the third guideline. The proscription against hindsight makes it unwise for a commission to supplement the reasonableness standard for prudence with other standards that look at the final outcome of a utility's decision, though consideration of outcome may legitimately have been used to overcome the presumption of prudence. The fourth guideline is to determine prudence in a retrospective, factual inquiry. The evidence needs to be retrospective in that it must be concerned with the time at which the decision was made. Testimony must present facts, not merely opinion, about the elements that did or could have entered into the decision at the time. Often the evidence for a state commission's retrospective, factual inquiry is developed through a staff investigation. Such a staff investigation can look at the past in great detail and therefore can be time consuming and expensive.

Following these guidelines is likely to be useful, perhaps necessary, for having a court sustain a commission decision regarding prudence.

However, because the prudence test is an emerging area of regulatory law, following these guidelines may not be sufficient to guarantee that a commission's decision based on prudence will be upheld.

Review of recent state commission prudence inquiries involving electric and gas utilities reveals that in only a few cases do commissions rely clearly and solely on the concept of prudence for reaching a judgment. Rather, in most cases commissions also reference the used-and-useful test or some other test when deciding if questionable costs should be included in rates. The review also shows that there have been many electric utility applications but few gas ones. The two principal areas of electric utility application have been construction cost overruns and plant abandonments, with capacity additions running a distant third.

Prudence inquiries involving construction cost overruns often depend on the results of a detailed staff investigation. Also, in cost overruns cases, use of the prudent investment test tends to work against utility interests in that the used-and-useful test alone, depending on how it is interpreted, is more likely to result in full cost recovery for an operational generating station.

The opposite is usually the case when the prudence test is applied to abandoned plant. Here, utilities introduce the prudent investment test in defense of their construction and abandonment decisions. In fact, the most frequent area of application of prudence in recent years has been where a utility plant has been abandoned or cancelled. Unlike construction cost inquiries, these prudence inquiries are usually not preceded by extensive staff investigations. In most cases, the presumption of prudence operates to allow recovery of most or all of the costs. However, a few cases have gone the other way.

Most state commissions have been reluctant to use the prudence test against decisions to add capacity. For many commissions, the mere existence of excess capacity is not necessarily indicative of an imprudent capacity planning decision, and, as long as state-of-the-art demand forecasting methods are used, there would be no finding of imprudence. Many commissions have dealt with cases where utilities defended excess capacity as resulting from prudent decision making. But several state commissions have held that the question of prudence applies not only to the initial investment decision but also to decisions made (or not made) during construction about the ongoing need for additional power. Thus, a failure to cancel a project that was prudently initiated, after it is no longer prudent to continue the project, can result in a finding of imprudence.

The recent emergence of the prudent investment test is mainly due to the higher risks and higher stakes faced by energy utilities, particularly by electric utilities, over the last 10 to 15 years. The higher risks relate primarily to uncertainties about costs, demand growth rates, and the supply of generation capacity needed for the future. Because the environment is riskier, the chance of error in utility planning is greater, and the opportunity for making an imprudent decision is greater than in the

past. The consequences of an imprudent decision are also greater--both in absolute and relative terms. Today's direct costs of construction and costs of capital are much higher than in the past. Further, electric construction work in progress for privately owned utilities in the United States as a percentage of net electric plant has increased continuously from 1967 through 1983, from 8 percent to 36 percent, so that the effect on the average company of excluding a large construction project from rates is much greater today than in the past.

Who suffers the consequences of an error--utility customers or utility investors--has become an increasingly important question for commissions as the stakes involved in utility investment decision making grow. State commissioners today are pulled between the obligation to keep utilities financially sound and able to provide reliable service to customers and the obligation to set rates at a level reasonably related to the costs of providing service. They have been forced to choose between these two obligations where large investment values are at stake and where commission action exposes either stockholders or ratepayers to severe financial losses.

The concept of prudence provides commissions with a principle that does not necessarily require an "all or nothing" decision in favor of one side, but can allow some sharing of the risks between investors and ratepayers. The prudent investment test is a tool that regulators are using to provide an answer to the question of who should bear which risks and associated costs. In practice, it seems that many regulators choose not to hold utilities responsible for risks affecting the electric industry as a whole. Instead, state commissions often apply the prudent investment test so as to hold utilities harmless, except for the consequences of decisions that were unreasonable at the time they were made. The test is used principally to hold utilities responsible for the risks over which management has substantial control.

Regular and strict use of the prudence test by state commissions to disallow major portions of large expenditures by utilities is intended to protect utility customers and to compel responsible and efficient utility decision making, but such regular and strict use may have other, unintended consequences. One consequence could be a utility policy of minimal future investment in service capacity. This seems likely to occur unless commissions also provide positive investment incentives or underinvestment penalties. Another possible consequence of strict prudence application is utility bankruptcy. Recent studies suggest that a likely effect of utility debt reorganization would be to increase capital costs and utility rates above the levels that would exist with a limited prudence penalty that did not cause bankruptcy. However, this finding depends heavily on several factors, including the overlapping authorities of the bankruptcy court and the state commission and the extent to which the commission is allowed to participate in the bankruptcy proceedings.

Between the extremes of utility underinvestment and utility bankruptcy are other possible consequences of strict prudence application that

represent permanent alterations of the relationships among the parties to a major utility construction project: utility management, the financial community, equipment vendors, architect-engineers, and construction firms. Altering these relationships could raise the costs of utility service because of increased capital costs, more formal "arm's length" dealings, higher construction contract bids, increased litigation among the parties, more detailed record keeping, and less technical innovation. But it is not possible to generalize about the net effect on utility rates of protecting customers from imprudently incurred costs in the short run, compelling utility managers and contractors to be more efficient in the long run, and altering relationships so as to increase long run costs.

Numerous issues about prudence need to be resolved as this area of regulatory law continues to emerge. One set of issues concerns articulating more fully in the hearing room both the nature of a prudent investment decision in the utility business and the regulatory procedures for judging the prudence of a utility decision. In particular, the relationship of the prudence standard to the used-and-useful standard must be clarified. Concerns about the decision-making process for major utility investments have led some utility representatives and some regulators to call for greater commission involvement in this process. A second set of issues concerns the appropriateness of such involvement. Still another group of issues relates to the consequences of regular and strict prudence application and what limitations, if any, ought to be imposed on such application. Of particular concern is the issue of when regulatory disallowance of cost recovery becomes confiscation.

Despite these uncertainties, the extensive contemporary use of the judicially developed prudent investment concept by state commissions demonstrates the vitality and usefulness of the concept. It is not confined to the capital cost component of ratemaking, but has been used to assess the reasonableness of decisions involving operating expenses as well. Under the existing regulatory framework, a utility's rate case is the only occasion for providing accountability to the consuming public and the investing public. Within this framework, the prudent investment test is emerging as a necessary and flexible regulatory tool for identifying types of risk and for placing the risk of utility mismanagement on utility owners.

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FOREWORD

The bylaws of The National Regulatory Research Institute state that among the purposes of the Institute are:

> ...to carry out research and related activities directed to the needs of state regulatory commissioners, to assist the state commissions with developing innovative solutions to state regulatory problems, and to address regulatory issues of national concern.

This report helps meet those purposes, since the subject matter presented here is believed to be of timely interest to regulatory agencies and to others concerned with electric and gas utility regulation.

Douglas N. Jones
Director
March 8, 1985

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CHAPTER 1

PRUDENCE AS AN EMERGING AREA OF REGULATORY LAW

Recently, the concept of prudence has been increasingly used by state utility regulatory commissions. This report contains an examination of the concept of prudence in public utility decision making and of the use of the "prudent investment test" in commission proceedings. The principal objective of this study is to provide useful information and analyses about the prudence concept to commissioners and their staffs who are faced with a judgment about what constitutes a prudent investment decision by a regulated company.

The immediate occasion for most recent applications of the prudence concept has been the turmoil in the electric utility industry. Many large generating units, particularly nuclear power plants, have been cancelled or abandoned. Other nuclear power plants under construction have experienced substantial construction cost overruns. And completed plants have often resulted in excess capacity because electric utility demand forecasts overestimated demand growth.

Recent public discussion of prudence has often loosely referred to "the prudence of a nuclear power plant" or the "prudence of a demand forecast," as if an object or a set of numbers were prudent or imprudent. In our view, prudence always relates to a decision--or the absence of a decision where one is needed. Hence, one can examine the prudence of a decision to construct a generating unit of a particular type and size. One can examine the prudence of a decision to continue or discontinue construction of a partially completed plant. One can examine the prudence of a decision to employ a certain system for managing a construction program and for controlling its costs. Also, one can examine the failure to make any one of these decisions in a case where deliberate choice appears to be required; this could be thought of as a decision to avoid

deciding. The point here, of course, is that it is the decision itself that is prudent or imprudent--not the generating unit or its cost or the demand forecast that motivated the decision to build the plant. Thus, recent electric utility applications of the prudence concept have, for the most part, related to decisions involving capacity planning. Commissions have considered the prudence of decisions that relied on overly optimistic demand forecasts and that resulted in either plant abandonment or excess capacity. Prudence has been considered for decisions regarding construction management practices that have led to excessive cost overruns and, in some nuclear cases, plants of questionable safety licensability.

The concept of prudence is, of course, applicable to the decisions of all regulated industries. The recent emergence of important electric utility applications of this concept, in what has come to be called the prudent investment test, has given it new prominence in public utility regulation. (Here, we refer to a significant application of the concept of prudence as a use of the prudent investment test.[1]) While most of the examples in this report deal with the recent application of the prudent investment test to electric utility decisions, examples of applications to gas utility decisions are also provided where appropriate.

The concept of prudence has existed for a long time in state utility regulation to ensure that only prudently decided capital expenditures are allowed in the rate base of a utility. For example, the concept of prudence was used as early as 1914 by the public service commission in Massachusetts.[2] While the concept has existed for a long time, it was not widely used by state commissions until after two decisions by the U.S. Supreme Court (the Natural Gas Pipeline case of 1942 and the Hope Natural Gas Co. case of 1944) which, taken together, provided a firmer legal basis

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[1]According to Black's Law Dictionary Revised 4th ed. (St. Paul: West Publishing Co., 1968), p. 1643, a test is "something by which to ascertain the truth respecting another thing; a criterion, guage, standard, or norm."

[2]See Middlesex & Boston Rate Case, 2 Ann. Rep. Mass. P.S.C. 99, 111-12 (1914).

for the use of the prudence concept.[3] Even then, the frequency of use of the concept by state commissions was relatively low for the next 30 years, compared to the recent frequency of application. Table 1-1 shows the number of times, according to the P.U.R. Digest, that the prudent investment test was used in some significant manner by a state commission during each of the 4 decades since the Hope case. There are five such cases reported in the first decade, only one in the next, three in the third, and then forty-two cases reported in the last.

Use of the prudent investment test by state commissions requires an understanding of the concept of prudence. Just what constitutes a prudent investment decision is addressed in chapter 2 of this report. It contains a review of the finance and management science literatures and discusses what constitutes a prudent investment decision for managers and financial professionals. The chapter then traces the historical judicial development of the concept of prudence in public utility law. It shows also how prudence is used in other areas of law dealing with fiduciary duties, including the law of bailments, the law of trusts, the law relating to corporate responsibilities, and the law of oil and gas leasing. The idea here is that some new perspective about the prudence of public utility decisions can be obtained by examining these ancillary fields where prudence is a central concept.

Chapter 3 contains a discussion of some recent state applications of the prudent investment test. The chapter begins with some guidelines to follow in a successful prudence application. The remainder of the chapter contains a discussion of recent state prudence cases by type of case. The types of cases discussed are those dealing with (1) construction cost overruns, (2) abandonment and cancellation of electric facilities, (3) capacity additions, and (4) abandonment and cancellation of gas facilities.

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[3]See Rose, "The Hope case and Public Utility Valuation," 54 Columbia Law Review 188, 212 (1954).

TABLE 1-1

STATE ELECTRIC AND GAS UTILITY CASES IN THE P.U.R. DIGEST THAT MAKE SIGNIFICANT USE OF THE PRUDENT INVESTMENT TEST, BY DECADE, FROM 1944 THROUGH 1983

Decade	Number of Cases	Case Citations	Prudence Applications
1944-1953	5	Re Arkansas Power & Light Co., 55 PUR (NS) 129 (Ark. PSC, 1944)	Uses the prudent investment standard to determine rate base
		Public Service Commission v. Louisiana Power & Light Co., 65 PUR (NS) 18 (La. PSC, 1946)	Adopts the prudent investment test as a valuation method
		Re Georgia Power Co., File No. 19314, Docket No. 8948-A (Ga. PSC, Nov. 22, 1948)	Uses the prudent investment test to determine rate base
		Mayor of Everett v. Malden and Melrose Gas Light Co., 78 PUR (NS) 129 (Mass. DPU, 1949)	Allows a plant in rate base as a prudent investment
		Re Consolidated Edison Co. of New York, 96 PUR 195, 231 (NYPSC, 1952)	Concerns construction cost overruns
1954-1963	1	Re Central Maine Power Co., 29 PUR3d 113 (Me. PUC, 1959)	Uses the prudent investment test to determine the portion of plant acquisition costs to be included in rate base
1964-1973	3	Re Consolidated Edison Co. of New York, 54 PUR3d 43, 112 (NYPSC, 1964)	Uses the prudent investment test to determine the plant acquisition costs to be included in rate base
		Re Consolidated Edison Co., 41 PUR3d 138 (NYPSC, 1968)	Uses the prudent investment test to determine the prudence of the initial decision to construct the facility and the construction contracting practices

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
		Re Consolidated Edison Co. of New York, 85 PUR3d (NYPSC, 1970)	Uses the prudent investment test on construction cost overruns
1974-1983	42	Re Consumers Power Co., 14 PUR4th 370 (Mich. PSC, 1976)	Uses the prudence test in the case of a plant cancellation
		Re Iowa Power & Light Co., 13 PUR4th 164 (Ia. SCC, 1976)	Concerns the Iowa SCC's authority to investigate the prudence of a utility investment
		Re the Detroit Edison Co., 20 PUR4th, 1, 13 (Mich. PSC, 1977)	Uses the prudence test in the case of a plant cancellation
		Re Virginia Electric Co., 44 PUR4th 46,49 (VSCC, 1977)	Uses the prudence test in the case of a plant cancellation
		In Re Detroit Edison Co., 24 PUR4th 362, 368 (Mich. PSC, 1978)	Uses the prudence test in the case of construction cost overruns
		Re Potomac Electric Power Co., 29 PUR4th 517 (D.C. PSC, 1979)	Uses the prudence test in the case of a plant cancellation
		Re Virginia Electric Co., PUR4th 65 (VSCC, 1979)	Uses the prudence test in the case of a plant cancellation
		Gulf State Utilities, 40 PUR4th 593 (La. PSC, 1980)	Uses the prudence test in the case of a plant cancellation
		Re Carolina Power & Light Co., Dkt. No. E-2 Sub 366 (NCUC, 1980)	Uses the prudence test in the case of a plant cancellation

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
1974-1983 (cont.)		Re Virginia Electric & Power Co., Case No. 9322 (WVPSC, February 1, 1980)	Uses the prudence test in the case of a plant cancellation
		Re Central Maine Power Co., Docket Nos. 80-25 & 80-66 (Me. PUC, Oct. 31, 1980)	Uses the prudence test in the case of a plant cancellation
		Re Potomac Electric Power Co., 36 PUR4th 139, 165-166 (D.C. PSC, 1980)	Recognizes the use of the prudent investment test for rate base determination
		Re Rochester Gas & Electric Corp., 41 PUR4th 438, 444 (NYPSC, 1981)	Concerns a failure to cancel plant
		Re Maine Public Service Co., 44 PUR4th 104 (Me. PUC, 1981)	Uses the prudence test in the case of a plant cancellation
		Re Northern States Power Co., 42 PUR4th 339 (Minn. PUC, 1981)	Uses the prudence test in the case of a plant cancellation
		Re Rochester Gas & Electric Co., 41 PUR4th 438 (NYPSC, 1981)	Uses the prudence test in the case of a plant cancellation
		Re Virginia Electric & Power Co., 44 PUR4th 46 (VSCC, 1981)	Uses the prudence test in the case of a plant cancellation
		Re Iowa Public Service Co., 46 PUR4th 339, 368 (Iowa SCC, 1982)	Concerns load forecasts and a failure to cancel
		In re Commonwealth Electric Co., 47 PUR4th 229 (Mass. DPU, 1982)	Concerns a failure to cancel plant
		In re Houston Lighting & Power Co., 50 PUR4th 157 (1982)	Concerns a failure to cancel plant

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
1974-1983 (cont.)		Re Potomac Electric Power Co., 50 PUR4th 500 (D.C. PSC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Bangor Hydro-Electric Co., 46 PUR4th 503 (Me. PUC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Rochester Gas & Electric Co., 45 PUR4th 386 (NYPSC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Duke Power Co., 49 PUR4th 483 (NCUC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Houston Lighting & Power Co., 50 PUR4th 157 (Tex. PUC, 1982)	Uses the prudence test in the case of a plant cancellation
		Re Central Vermont Public Service Corp., 49 PUR4th 372 (Vt. PSB, 1982)	Uses the prudence test in the case of a plant cancellation
		Wisconsin Public Service Corp. v. PSC, 325 N.W.2d 867 (Wis., 1982)	Overturns state commission decision that denied utility recovery of prudently incurred plant cancellation cost
		Re Carolina Power & Light Co., 49 PUR4th 188 (NCUC, 1982), reversed in part, 55 PUR4th 582 (NCUC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Boston Edison Co., 46 PUR4th 431 (Mass. DPU, 1982) affirmed 455 N.E.2d 414 (Mass., 1983)	Concerns a failure to cancel plant

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
1974-1983 (cont.)		Re Iowa Power & Light Co., 51 PUR4th 405, 411 (Ia. SCC, 1983)	Concerns load forecasts
		Re Consumers Power Company, 52 PUR4th 536 (Mich. PSC, 1983)	Uses the prudence test in a temporary abandonment
		Re United Illuminating Co., 55 PUR4th 252 (Conn. DPU, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Commonwealth Electric Co., 47 PUR4th 229 (Mass. DPU, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Detroit Edison Co., 52 PUR4th 318 (Mich. PSC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Atlantic City Electric Co., 51 PUR4th 109 (NJBPU, 1983)	Uses the prudence test in the case of a plant cancellation
		Pennsylvania Public Utility Commission v. Duquesne Light Co., 52 PUR4th 644 (PaPUC, 1983), affirming 51 PUR4th 198 (PaPUC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Central Illinois Light Co., 57 PUR4th 351 (Ill. CC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Carolina Power & Light Co., 55 PUR4th 582 (NCUC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Virginia Electric & Power Co., 54 PUR4th 1 (WVPSC, 1983)	Uses the prudence test in the case of a plant cancellation

TABLE 1-1--Continued

Decade	Number of Cases	Case Citations	Prudence Applications
1974-1983 (cont.)		Re Union Electric Co., 53 PUR4th 565 (Ill. CC, 1983)	Uses the prudence test in the case of a plant cancellation
		Re Wisc. Pub. Serv. Corp., 52 PUR4th 389 (Wis. PSC, 1983)	Uses the prudence test in the case of a plant cancellation
		Pa. Pub. Util. Comm'n v. Pa. Power & Light Co., 55 PUR4th 185 (PaPUC, 1983)	Uses the prudence test in the case of a plant cancellation

Source: Public Utilities Report Digests.

Chapter 4 develops the theme that a riskier utility environment is the cause of the recent prominence of the prudence test. For electric and gas utilities, the environment for investment decision making has been riskier over the last 10 years than previously. Because of the higher risks, the chance of error in decision making is greater and the consequences of error are greater than before. The prudent investment test is evolving into a regulatory tool for allocating the risks associated with utility decision making.

Chapters 5 and 6 look toward future applications of the concept of prudence. Chapter 5 contains a discussion of the possible utility strategies and financial consequences that could result from the use of the prudence test, and chapter 6 deals with issues yet to be resolved. Included in chapter 6 is a discussion of the relationship of the prudence test to the used-and-useful test, the emerging issues that the courts must ultimately resolve, and the authors' considerations about the possible future of the concept of prudence as a regulatory tool.

CHAPTER 2

THE PRUDENT INVESTMENT DECISION

The recent evolution of the application of the concept of prudent investment as a requirement governing public utility financial decision making reflects concern over the soundness of such utility investment decision making. But what constitutes a prudent investment decision?

To answer this question, we reviewed the finance and management science literatures and reviewed the relevant legal history to understand the roots of the concept of a prudent investment, particularly as it relates to public utilities. The review of the management science and finance literature with respect to prudence was undertaken to determine a generally accepted mode of behavior for managers making large capital investment decisions. As a major part of this effort the authors searched cases, commission orders, law journals, and restatements of law to find examples of how the concept of prudence has been used in public utility law and other related areas of law.

Prudent Investment Decisions in Finance and Management Science

Investment decision rules in finance and management science were developed to guide the decisions of managers, principally of unregulated firms. These rules may not fully apply to the decisions of utility managers. Regulators may expect managers to provide service at the lowest reasonable cost. Stockholders expect managers to maximize profits, subject to the constraints set down by regulators. At times these expectations may be in conflict. The finance and management science rules discussed here relate more to stockholder expectations. The legal history discussed next treats the obligations of utilities to customers and hence relates more to the expectations of regulators.

nuclear power plant should be ignored. The NPV of completing the plant and generating revenues should be compared to the NPV of abandoning the plant and taking a tax write-off. The plan with the higher NPV should be chosen.

For an unregulated company, such a decision is then a matter of doing the calculation. For a regulated company, the decision involves an assessment of the probable regulatory treatment of cancelled plant on the one hand versus treatment of possible cost overruns or excess capacity on the other hand. The effect of commission policy on utility investment strategy is examined further in chapter 5.

The finance literature agrees that investment decisions depend on expected incremental after-tax cash flows and that those cash flows should be valued using the NPV method. The NPV method requires discounting cash flows at a discount rate commensurate with the risk of the project. Disagreement in finance literature arises about what risk is relevant and how the discount rate should be adjusted for relevant risk.

For regulated companies, these are not only the usual risks relating to costs, demand, and supply, but also risks related to the uncertainty of regulatory treatment. The latter may be particularly hard to quantify in decision models.

Most textbooks advocate the use of the Capital Asset Pricing Model (CAPM), or, in special circumstances, the Certainty Equivalent method (CEQ). As mentioned, some authors advocate use of a newer model, the Arbitrage Pricing Theory (APT). Still other authors argue that ignoring individual risk, as is done in the CAPM and the APM, is wrong and advocate using overall risk as one factor when making investment decisions. The most theoretically precise model seems to be the Time-State Preference model, but this model does not seem to be ready for practical decision making yet.[2]

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[2]See Stewart C. Myers, "A Time-State Preference Model of Security Valuation," Journal of Financial and Quantitative Analysis 3 (March 1968): 1-34. Also see Charles W. Haley and Lawrence D. Schall, The Theory of Financial Decision, 2d ed. (New York: McGraw-Hill, 1979).

By the beginning of 1984, approximately thirty-five public utility commissions used the CAPM to determine cost of capital. It is an elegant theory that describes risk/return tradeoffs in perfect capital markets.[3] This theory argues that with perfect capital markets all investors would own perfectly diversified portfolios. The only risk that matters to such investors is undiversifiable risk, sometimes called market risk. This market risk can be measured somewhat imprecisely for individual companies, but reasonably accurately for industries. A standardized measure of this risk is called "beta," and finance textbooks and stockbrokers often refer to a company's beta risk. By knowing a company's beta, the company's cost of capital can be estimated using something called the "Security's Market Line," and this cost of capital is the discount rate that should be used in the NPV method when evaluating projects.

The CAPM is strictly valid, for technical reasons, only when risk increases at a uniform rate through the life of a project. Some projects, such as building nuclear power plants, may be more risky during the construction phase than during the operating phase of the project. Other projects, such as drilling an oil well, may have the greatest risk at the end of the project. When risk does not grow linearly through the project, the CAPM must be modified to the Certainty Equivalent method (CEQ).[4] The CEQ involves calculating the certain equivalent cash flow that an executive would trade for a given risky cash flow and then discounting that certain equivalent cash flow back to the present at the riskless interest rate. In other words, the CEQ method adjusts the cash flow for risk, not the

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[3]See William F. Sharpe, "Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk," Journal of Finance 19 (September 1964): 425-447; John Litner, "Security Prices, Risk, and Maximal Gains from Diversification," Journal of Finance 20 (December 1965): 587-615; and Jan Mossin, "Equilibrium Prices in a Capital Asset Market," Econometrica 34 (October 1966): 768-783.

[4]Alexander A. Robichek and Stewart C. Myers, "Conceptual Problems in the Use of Risk-Adjusted Discount Rates," Journal of Finance 21 (December 1966): 727-730.

discount rate. A method of calculating certain equivalent cash flows that is consistent with the CAPM is explained in some textbooks.[5]

Some authors claim that the CAPM is misspecified and produces biased estimates of the cost of capital.[6] Evidence for the misspecification is the consistently positive intercepts (alphas) obtained when estimating betas for the electric utility industry. Two authors, Meyer and Roll, propose using an alpha adjustment to the cost of capital obtained from the CAPM.[7] A more recent theory of asset valuation is the Arbitrage Pricing Theory (APT) by Ross.[8] Roll and Ross argue that the APT, by using several market risk factors, avoids the one-dimensional errors caused by using only one measure of risk in the CAPM.[9] They show that the APT produces cost of capital estimates for the electric utility industry that are nearly 100 basis points higher than those produced by the CAPM and have alphas that average zero, as predicted by theory. The Roll and Ross cost of capital estimate appears to be virtually identical to cost of capital estimates produced through the alpha-adjustment methods mentioned above.

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[5]For example, see Richard Brealey and Stewart Myers, Principles of Corporate Finance (New York: McGraw-Hill Co., 1982).

[6]See Chartoff et al., "The Case Against the Use of the Capital Asset Pricing Model in Public Utility Ratemaking," 3 Energy Law Journal 67 (1983).

[7]See Testimony of Dr. Richard F. Meyer (Jan. 30, 1980) at 58-61, In the Matter of the Valuation Proceedings under Section 303(c) and 306 of the Regional Railroad Reorganization Act of 1973, Special Court Misc. No. 76-1; and Testimony of Dr. Richard W. Roll at 74-80 (Jan. 30, 1980), In the Matter of the Valuation Proceedings under Section 303(c) and 306 of the Regional Railroad Reorganization Act of 1973, Special Court Misc. No. 76-1; These transcripts are available from the Special Court for the Regional Rail Reorganization Act, U.S. Court House #1820A, 3rd St. and Constitution Avenue, N.W., Washington, D.C. 20001.

[8]Stephen A. Ross, "The Arbitrage Theory of Capital Asset Pricing," Journal of Economic Theory 13 (December 1976): 341-360.

[9]Richard W. Roll and Stephen A. Ross, "Regulation, the Capital Asset Pricing Model, and the Arbitrage Pricing Theory," Public Utilities Fortnightly, May 26, 1983, pp. 22-28.

Nearly all the finance textbooks advocate the use of sensitivity analysis and computer simulations to estimate the overall risk of major projects. Few textbooks seem to realize that analyzing risk in these ways is inconsistent with the CAPM conclusion that only market risk matters, and no textbook describes how to make a decision given a project's sensitivity and simulation results. Brigham points out that there is no quantitative rule available for using simulations and sensitivity results and advocates using "judgment."[10]

All projects involve a risk of failure, and large projects involve a risk of bankruptcy. In finance literature, bankruptcy costs are defined as the "cost of the funeral." In a perfect capital market, when a company defaults on a debt obligation, the company's assets are assumed to be costlessly turned over to the bondholders. In practice, bankruptcy results in a substantial amount of the assets being sold to pay for attorneys' fees and bankruptcy court costs instead of being paid to the bondholders. Bondholders know this and charge in advance an interest premium on their bonds equal in value to the expected bankruptcy costs.

Van Horne points out that bankruptcy costs violate the CAPM perfect capital market assumption and are reason enough to consider overall risk in making investment decisions.[11] He advocates ranking projects both by NPV and by overall risk, using judgment when the project with the highest NPV also has the highest overall risk.

Petty gives plausible but, we believe, erroneous advice.[12] He advocates using sensitivity analysis and computer simulations to estimate the probability of bankruptcy and then adjusting the expected cash flows by the expected cost of bankruptcy. He overlooks the fact that stockholders

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[10]Eugene F. Brigham, Financial Management Theory and Practice, 3d ed. (Chicago: Dryden Press, 1982).

[11]James C. Van Horne, Financial Management and Policy, 6th ed. (Englewood Cliffs, N.J.: Prentice-Hall, 1983).

[12]William J. Petty et al., Basic Financial Management, 2d ed. (Englewood Cliffs, N.J.: Prentice-Hall, 1982).

do not pay bankruptcy costs directly. Instead, as the probability of bankruptcy increases, the interest expense of debt financing increases. The amount of this increase is difficult to compute.

Regulated utilities seek to reduce the risk to stockholders, particularly the risk of bankruptcy, by obtaining regulatory approval for ratepayer sharing of risks. This gives regulators and ratepayers a stake in the prudence of utility investment decisions--a theme developed further in chapters 4 and 5.

Management Science Literature

Management science literature discusses investment decisions as part of a topic called "decision theory." A typical introduction to decision theory discusses decisions under three circumstances: certainty, risk, and uncertainty.[13]

Decision making under certainty is trivial: the decision maker simply chooses the largest payoff. Decision making with risk means decision making with a known probability distribution, usually for a decision to be made repeatedly, such as an inventory stocking problem. Again the decision is easy: choose the largest expected payoff, or equivalently, the minimum expected loss. Uncertainty is defined as an unknown probability distribution, usually for a unique decision. Lee, among others, gives a list of proposed decision rules for uncertainty, such as Minimax, Maximin, and Minimize Regret.[14] Hillier and Lieberman point out that these rules are not accepted by most management science practitioners, that the rules ignore probabilities, and that the rules usually assume malevolent opponents rather than nature, which is assumed to be neutral.[15]

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[13]Robert J. Thierauf, An Introductory Approach to Operations Research (Santa Barbara: John Wiley and Sons, Inc., 1978).

[14]Sang M. Lee, Introduction to Management Science (Chicago: Dryden Press, 1983).

[15]Frederick S. Hiller and Gerald J. Lieberman, Operations Research, 2d ed. (San Francisco: Holden-Day Inc., 1974).

One rule that does enjoy general acceptance is Baysian analysis, which uses subjective probability estimates when objective estimates are unavailable.[16] The Baysian rule then advocates maximizing expected profits. Sometimes an investor can purchase more information before making a decision. Baysian analysis allows an investor to estimate the expected value of the new information. The investor can then decide whether to purchase the new information by comparing its cost to its expected value.

Some management science textbooks acknowledge that maximizing expected profits may not be the best objective function.[17] Maximizing utility seems to be as close to calculating a risk/return tradeoff as management science comes. In none of this literature is there a discussion about comparing payoffs coming in different years. Siemans, Marting, and Greenwood is the only management science book that was found that discussed the Net Present Value rule, so common in the finance literature, and it did not discuss how to adjust the discount rate for risk.[18]

In sum, management science literature has developed sophisticated techniques such as Baysian analysis and linear programming for maximizing an expected payoff function, but has little to say about the payoff function itself. From the finance literature, however, we know that the expected payoff functions must be discounted cash flows, and that the discount rate must be commensurate with the relevant risk of the investment.

However, while these rules for making prudent investment decisions are useful for utility managers as they seek the greatest return for utility investors, they must be tempered by the legal obligation of the utility to invest prudently from the viewpoint of serving the public interest.

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[16]For example, see Fadil H. Zuwaylif et al., Management Science: An Introduction (Santa Barbara: John Wiley and Sons Inc., 1979).

[17]For a discussion on maximizing utility, see Michael Q. Anderson, Quantitative Managment Decision Making (Montery: Brooke/Cole Publishing Co., 1982); Robert E. Markland, Topics in Management Science (New York: John Wiley and Sons Inc., 1979); and Bernard W. Taylor, Introduction to Management Science (Dubuque: Wm. C. Brown Co. Publishers, 1982).

[18]Nicolai Siemans et al., Operations Research (New York: The Free Press, 1973).

Prudent Investment Decisions and the Law: Obligations of Public Utilities

The concept of a prudent investment is a regulatory oversight standard that attempts to serve as a legal basis for adjudging the meeting of utilities' public interest obligations, specifically in regard to rate proceedings.

The purpose of the remainder of this chapter is to analyze the history and judicial application of the legal concept of prudent investment as it relates to the obligations of public utilities. As part of this analysis, the concept of prudence is explored as a legal standard of business conduct in relation to analogous regulated business activities other than the operation of public utilities: activities including the operation of trusts, oil and gas development, and others. The examination of these analogous activities may provide additional insights appropriate for state commission application to the public utilities.

Although much has been written recently about the various elements of the concept of public utility prudent investment obligations, no apparent comprehensive treatment of the subject and related legal areas has emerged. For this reason, a thorough technical discussion of the subject matter is needed and may advance the public discussion. This analysis attempts to develop a legal framework within which the concept of prudent investment can be legally defined as it applies to public utilities and its usefulness as a regulatory standard can be evaluated.

An appropriate starting point in the discussion of the legal concept of prudence is to provide a general legal definition of the term for use throughout this analysis. The term "prudence" is broadly defined as:

> Carefulness, precaution, attentiveness, and good judgment, as applied to action or conduct. That degree of care required by the exigencies or circumstances under which it is to be exercised....This term in the language of the law, is commonly associated with "care" and "diligence" and contrasted with "negligence."[19]

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[19] Black's Law Dictionary, p. 1392.

In a similar fashion, the term "prudent" is generally defined as:

> Sagacious in adapting means to an end, circumspect in action or in determining any line of conduct, practically wise, judicious, careful, discreet, circumspect, sensible.[20]

Several judicial decisions have also provided general definitions of the terms. For example, it has been held that "prudent" and "cautious" are synonyms.[21]

"Prudent" has also been held to mean exercising sound judgment or being recognized by practical wisdom.[22]

Although these general definitions give some guidance as to the legal usage of the terms in a variety of contexts, they are at best only a meager beginning point in the legal analysis of the concept of public utility prudent investment requirements.

The concept of prudence is used throughout the law as a description of a standard of conduct owed to others. In the law of torts, the "ordinary reasonably prudent man" is well known for the careful conduct of his own actions in avoiding personal injury to others, both with respect to his actions and with respect to the foreseeability of their consequences.[23]

Beyond the law of torts, other areas of law have found use for the concept of prudence as a standard of care in the conduct of business affairs. The economic use of property where the legal duty of care is owed

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[20] Id.

[21] See, State v. Norton, 286 N.W. 476, 479, 227 Iowa 13 (1939).

[22] See, Westbrook v. Watts, 268 S.W.2d 694, 698 (Tex. Ct. App. 1954).

[23] See, Prosser on Torts (4th ed., 1971) Section 32, entitled "Negligence: Standard of Conduct," p. 150.

to persons other than the manager is most analogous to the concept of prudent investment obligations of utilities. These areas include the legal obligations arising in the context of mineral development leases, trust management, and estate management--all activities where legal obligations were developed at Common Law and all predating the use of the concept of prudence in the context of utility management.

It seems likely that the concept of prudence was borrowed from other areas of law and made to apply to public utility regulation. In fact, the historical analysis in the next section offers one piece of evidence demonstrating this.

It is appropriate to mention at the outset that the law does not generally intrude into the managerial decision process, except in the area of regulated activities. In the arena of general corporate law, for example, a broad range of business discretion is vested with management, which is deliberately insulated from legal recourse under the so-called "business judgment rule." As one corporate law treatise puts it:

> The "business judgment" rule sustains corporate transactions and immunizes management from liability where the transaction is within the power of the corporation (intra vires) and the authority of management, and involves the exercise of due care and compliance with applicable fiduciary duties.
>
> Corporate management is vested in the board of directors. If in the course of management, directors arrive at a decision, within the corporation's powers (intra vires) and their authority, for which there is a reasonable basis, and they act in good faith, as the result of their independent discretion and judgment, and uninfluenced by any consideration other than what they honestly believe to be the best interests of the corporation, a court will not interfere with internal management and substitute its judgment for that of the directors to enjoin or set aside the transaction or to surcharge the directors for any resulting loss.
>
> Business judgment thus, by definition, presupposes an honest, unbiased judgment (compliance with fiduciary duty) reasonably exercised (due care), and compliance with other applicable requirements.
>
> Although the business judgment rule is usually stated in terms of director functions, it is no less applicable to officers in the

> exercise of their authority and may be applicable to controlling shareholders when they exercise their more extraordinary management functions.[24]

Thus, there is no general legal obligation that imposes rigorous standards of conduct in the ordinary course of business. However, many areas of law, because of the peculiar legal relationships that arise, have developed standards to protect the rights of individuals not in control of decision making or business planning. The prudent investment concept is such a standard.

For all these reasons a detailed recapitulation of the historical development and analysis of prudent investment obligations of public utilities provides a significant insight into the contemporary use of prudence as a regulatory tool.

Historical Judicial Development

The starting point in most analyses of the concept of prudent investment obligations of public utilities is a footnote in the separate opinion of Mr. Justice Brandeis in 1923 in Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission, in which he noted:

> The term prudent investment is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown.[25]

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[24]Harry G. Henn, Corporations (St. Paul: West Publishing Co., 1961) at Sec. 233, entitled "Business Judgment Rule," pp. 364-364.

[25]Missouri ex. rel. Southwestern Bell Telephone Co. v. Public Service Commission, 262 U.S. 276 (1923), p. 289, note 1.

The footnote was a reference to Brandeis' discussion of utility rates:

> The thing devoted by the investor to the public use is not specific property, tangible and intangible, but capital embarked in the enterprise....The compensation which the Constitution guarantees an opportunity to earn is the reasonable cost of conducting the business Cost includes not only operating expenses, but also capital charges. Capital charges cover the allowance, by way of interest, for the use of the capital,...the allowance for the risk incurred; and enough more to attract capital....Where the financing has been proper, the cost to the utility of the capital, required to construct, equip and operate its plant, should measure the rate of return which the Constitution guarantees opportunity to earn.[26]

Brandeis used the concept of prudent investment in this context:

> ...adoption of the amount prudently invested as the rate base and the amount of the capital charge as the measure of the rate of return [would provide a]...basis for decision which is certain and stable. The rate base would be ascertained as a fact, not determined as a matter of opinion. It would not fluctuate with the market price of labor, or materials, or money...[27]

Although the Southwestern Bell case appears to be the first Supreme Court case in which the concept of prudent investment gained recognition, it is obvious from Justice Brandeis' references that he relied upon both earlier state case law and various law reviews dealing with utility rates in the formulation of his now famous articulation of prudent investment.

Among the authorities relied upon by Justice Brandeis were two law review articles published in the Michigan Law Review in 1917 and 1923 that were written by Edwin C. Goddard, who served as a professor of law at the University of Michigan for several years shortly after the turn of the century. One of Goddard's early works was a case book entitled Cases on the Law of Bailments and Carriers and of Service by Public Utilities, which

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[26] Id., pp. 290-292, and 306.

[27] Id., pp. 306-307.

was originally copyrighted in 1904 and updated and published again in 1928.[28]

What is interesting about the 1928 version of the bailment and utility case book is the juxtaposition of the two seemingly unrelated and diverse topics. The law of bailments deals with the obligations and liability of custodians of goods and is generally not regarded as related to public utility law. Goddard, however, saw a relationship between the two topics that is revealed in his preface:

> The reasons for treating these subjects in one book are mainly two, the exigencies of the law school curriculum and an interrelation that permits a natural development of these subjects in one course... The bailment relation is one of the fundamental concepts of the law, and deserves more than the incidental and fragmentary reference it receives in the property law courses. Better than any other subject of the law it provides material for the study of care and negligence, and here it is vitally related to the most important feature of common carrier law, viz. the liability of the common carrier. And here we are entering the whole field of public utilities, of which the common carrier is easily foremost in extent and importance. Incidentally, the pledge and the innkeeping relation, the telegraph and the telephone, take their places in a natural way.[29]

Thus, it would seem that Goddard saw an important relationship between the obligations of care in the management of property for others under bailment law and public utility law, a fact that is demonstrably corroborated by his inclusion of then contemporary cases dealing with the concept of prudence. For example, one of the bailment cases of the period that

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[28]Edwin C. Goddard, Cases on the Law of Bailments and Carriers of Service by Public Utilities (Chicago: Callagan and Company, 1928). Between the two versions of this case book, Goddard published another case book entitled Cases on Principal and Agent (St. Paul: West Publishing Co., 1914).

[29]Goddard, Cases on the Law of Bailments, p. iv.

Goddard chose to include in the book was Hanes v. Shapiro,[30] a case that extensively cited Judge Story on the concept of prudence. Because it may be assumed that Goddard saw the relationship of diverse areas of law, the references to his law reviews on prudence take on an added significance in terms of the historical antecedents to the use of prudence in relation to utilities and are worthy of extended consideration.

The first Goddard article relied upon by Brandeis was an attempt to develop a regulatory construct of utility valuation to which Goddard referred as the "efficient investment theory." The article proposed the efficient investment theory as a solution to the dilemma of whether to use actual cost or reproduction cost as the basis for setting utility rates:

> In this connection the use of the terms "value" and "valuation" is unfortunate. It is not value in any ordinary sense that is being sought, as has often been noticed. The basis for all dealings involving purchase and rate making should be, not actual cost, not reproduction cost, not market value, not stock and bond issue. It should be what has been well called the "efficient investment," i.e., the actual amount honestly and prudently invested in the utility, under normal conditions; no more, no less. The "efficient investment" theory eliminates all consideration of losses due to mismanagement. Those must be charged to stockholders. "The company is held to the same standard of honesty and prudence in the management and maintenance as in the original acquisition of its properties." It takes no account of bad property investments, it eliminates all the objectionable elements that have been urged against the actual cost theory. As it has been stated in a recent case by the Washington Commission, "it would seem equitable, just and fair that the public should be required to furnish fair, just, and reasonable compensation for the reasonable and necessary detriment a utility has suffered by reason of its service to the public....
>
> It cannot be urged that the adoption of the "efficient investment" as the valuation base would not be attended with difficulties.

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[30]Hanes v. Shapiro, 168 N.C. 24, 84 S.E. 33 (1915), cited by Goddard in his Cases on the Law of Bailment, p. 187.

> But they are no greater than have attended all fair value computation on the indefinite rule of the past, even when the cost-of-reproduction-less-depreciation, and plus some uncertain, but considerable, other items has been adopted. And once the initial difficulties are past, what was before all uncertainty and matter of dispute becomes a certain as ledger balances.... [Footnotes deleted and emphasis added.][31]
>
> To secure a good service it is to the public interest to make investment in public utilities attractive, and to give a return on such investment not merely equal to, but somewhat higher than, returns in kindred private enterpries. Returns should not be too high, however, or they will attract not the investing public, but speculators and manipulators, to the detriment alike of the public and of honest investors. It is also to the public interest to assure, as far as possible, to the investor in public utilities, a return on what is really put into the utility in good faith and with prudence and good judgment. Such a condition would do much to substitute for the antagonism and often unreasonable suspicion now existing between the public and public service companies that harmonious and understanding relation based upon mutual respect for rights and observance of duties that is so needed to make public service satisfactory. Once past the initial difficulties, which are not at all insurmountable, the "efficient investment" theory will insure between the public and public utilities a relationship which is fair to both, which will attract the necessary capital by making the investment almost as safe as governmental securities, and which will make possible and probable an adequate and efficient service. [Emphasis added.][32]

In the second article, Goddard more specifically embraced the use of a prudent investment standard and retreated from defining the notion as "efficient investment." His conclusion clearly indicates that the concept was intended to reconcile the continuing legal debate about ratemaking valuation by defining a more practical approach. It is also evident that he was concerned about the constitutional implications of the prudent investment standard in light of earlier Supreme Court rate decisions:

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[31]Goddard, "Public Utility Valuation," 15 Michigan Law Review 203, 223-224 (1917).

[32]Id., p. 227.

> The conclusion of this review of recent cases is that the Commissions, working at first hand with the practical problems of valuation, generally lean more and more decidely toward fixing value--so called--of public utilities on prudent investment, largely, and in not a few cases wholly. The courts, on the other hand, still wallow in the uncertainties of the rule, which is scarcely a rule at all, of Smyth v. Ames, making value a question of judgment. In the cases, judgments continue to vary as widely as ever. The courts are probably too firmly committed to a consideration of various elements to expect them to adopt the definite rule of fixing base values on prudent investment. Whether legislatures will step in here, and whether a legislative act making prudent investment the basis would be held to be constitutional is for the future to reveal. [Emphasis added.][33]

Thus we see that, in principal reliance upon the Goddard articles, Justice Brandeis introduced the concept of prudent investment into what was already an ongoing legal debate over methods of utility valuation for the purposes of ratemaking. Two observations may be made about Goddard's proffer of the prudent investment concept to reconcile the valuation debate. First, his formulation itself is rather abstract in that it did not articulate specific examples of application of the concept. And, second, he offered no analysis of the constitutionality of the concept. In essence, his approach was pragmatic and suggested merely what ought to be done.

An important refinement in the Goddard approach, upon which Justice Brandeis obviously relied in his Southwestern Bell opinion, was advanced in a 1922 Yale Law Journal article:

> The essential theory which seems more just is that investment in public utility securities, whether denominated as stock or bonds, should be regarded practically as an investment in bonds bearing a fixed return with the principal protected against impairment through appropriate depreciation and maintenance charges. It would seem a sound principle to regard the operators of public utilities as trustees of the service for the public and of the capital invested for the security holders. It should be their obligations to keep costs as low as consistent with efficient service and to do all in their power to insure investors of capital a safe non-speculative rate of return.

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[33]Goddard, "Public Utility Valuations and Rates," note and comment, 19 Michigan Law Review 849, 852-853 (1921).

> Public utility operators who recognize these obligations cannot support theories of public utility regulation which make public utility securities a speculative investment and subject public utility service to the hazards of speculative enterprise.
>
> Public utility operators and public officials alike, who are not financial or political demagogues, should join in a demand for the establishment in the courts and commissions of the doctrine that a reasonable rate for public utility service should be ascertained by the addition to current operating expenses of the amount of interest required to recompense at market rates the capital actually and prudently employed in producing the service and to induce the further investment of capital needed for desirable extensions and improvements....
>
> If the courts can be brought to realize that the word "value" means nothing except a resultant of earning power and that the value of a property cannot be ascertained until after its earning power is fixed, then figures showing the prudent investment in a property can be presented, not as evidence of the value of the property, but as evidence of the cost to the owners of the property of providing public service. The courts viewing the operators of the property as trustees who must obtain from the public reimbursement for outgoes, will find the evidence of the prudent investment in the property relevant and essential to determine the amount of capital upon which the operators must pay the market rate in order to continue to furnish service. In this investigation there is no inquiry whatsoever as to the value of the property. In fact, the question of the value of the property is entirely irrevelant. [Emphasis added.][34]

This description of prudent investment obligations drew on the concept of prudence in trust law in its characterization of public utilities as enterprises being conducted as trusts for the benefit of the public. Thus, through his general reference to the concept of prudent investment in Southwestern Bell, Justice Brandeis introduced into the middle of a constitutional debate about utility valuation an alternative approach.

Without digressing too far, it is helpful to examine the status of the constitutional debate at the time of the Brandeis opinion. In 1898, the

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[34]Richberg, "A Permanent Basis for Rate Regulation," 31 Yale Law Journal 263, 278-279 (1922).

U.S. Supreme Court confronted the first major constitutional issue concerning utility ratemaking in the context of challenge against commission set utility rates based upon alleged violations of the injunction of the Fourteenth Amendment against taking without just compensation. In Smyth v. Ames,[35] the Supreme Court faced the question of whether a state's regulatory establishment of inadequate rates for a railroad constituted an unconstitutional take of property. The Court held that no constitutional violation occurred so long as the ratemaking process assured that utilities received a fair rate of return on capital investment. Almost immediately the question moved to what constituted capital investment upon which the return was to be gauged.

In 1920 the Supreme Court held in Ohio Valley Co. v. Ben Avon Burrough[36] that the nature of the constitutional issues involved in utility ratemaking was such as to require judicial scrutiny. Finally, in 1923 in a case decided just before Southwestern Bell, the Supreme Court addressed more specifically the entitlement of utilities to reasonable rates of return in the landmark Bluefield decision:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[37]

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[35]Smyth v. Ames, 169 U.S. 466 (1898).

[36]Ohio Valley Co. v. Ben Avon Burrough, 253 U.S. 287 (1920).

[37]Bluefield Water Works & Improvement Company v. Public Service Commission, 262 U.S. 679, 692-693 (1923).

Justice Brandeis' reference to prudent investment in Southwestern Bell takes on added significance in light of the fact that the same Court had just decided Bluefield without characterizing valuation determination there in terms of prudent investment. It may be fairly concluded, as subsequent events corroborate, that Brandeis introduced the concept without either consensus among his colleagues on the Court or a very clear articulation of its legal definition.

Subsequent utility cases before the Supreme Court reveal that the Brandeis approach did not gain immediate acceptance. Indeed the use of reproduction valuation in utility rate cases continued. In 1927 in McCardle v. Indianapolis Water Co.,[38] the Supreme Court laid down a rule that seeingly mandated the use of reproduction under the Smyth case.

However, in Los Angeles Gas Co. v. Railroad,[39] the Court upheld a valuation from which reproduction cost had been excluded, thereby leaving the status of reproduction cost as the basis for utility ratemaking in doubt. Prudent investment, however, was not a concept utilized in rate analysis by the Court.

In 1935 in the West Ohio Gas case, the Court talked around the concept of prudence without actually mentioning it:

> A public utility will not be permitted to include negligent or wasteful losses among its operating charges. The waste or negligence, however, must be established by evidence of one kind or another, either direct or circumstantial. In all the pages of this record, there is neither a word nor a circumstance to charge the management with fault....There is not even the shadow of a warning to the company that fault was imputed and that it must give evidence of care. Without anything to suggest that there was such an issue in the case, the commission struck off 2%, it might with as as much reason have struck off 4 or 6. This was wholly arbitrary.[40]

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[38]McCardle v. Indianapolis Water Co., 272 U.S. 400 (1927).

[39]Los Angeles Gas Co. v. Railroad Commission, 289 U.S. 287 (1933).

[40]West Ohio Gas Co. v. Public Utilities Commission of Ohio (No. 1), 294 U.S. 63, 68 (1935).

And, in a case decided a year later in which important issues concerning managerial judgment, perhaps appropriate for reference to prudent decision making in the context of permissible rates, the Court again avoided reference to prudence:

> The contention is that the amount to be expended for these purposes is purely a question of managerial judgment [under the Packers and Stockyards Act]. But this overlooks the consideration that the charge is for a public service, and regulation cannot be frustrated by a requirement that the rate be made to compensate extravagant or unnecessary costs for these [salesmen's salaries] or any purposes. We are not persuaded that the conclusions as to proper allowances on this head were without substantial support in the record.[41]

Not only was the concept of prudent investment not readily acceptable or used by the majority of the Supreme Court, but the matter of utility valuation remained in flux. In 1938, for example, the Supreme Court allowed to stand the use of historical cost as a measure of valuation for rate determination.[42]

A specific reference to prudent investment was not made by the Court until 1942 in the Natural Gas Pipeline case, and then only in a minority concurring opinion of Justices Black, Douglas, and Murphy:

> As we read the opinion of the Court, the [Federal Power] Commission is now freed from the compulsion of admitting evidence on reproduction cost or of giving any weight to that element of "fair value." The Commission may now adopt, if it chooses, prudent investment as a rate base--the base long advocated by Mr. Justice Brandeis. And for the reasons stated by Mr. Justice Brandeis in the Southwestern Bell Telephone case, there could be no constitutional objection if the Commission adhered to that formula and rejected all others.[43]

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[41]Acker v. United States, 298 U.S. 426, 431 (1936).

[42]Railroad Commission v. Pacific Gas Co., 302 U.S. 288 (1938).

[43]Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 606 (1942).

As the immediate comments on the Natural Gas Pipeline case demonstrated, the injection of Brandeis' prudent investment concept back into the rate debate after a period of dormancy caused great confusion among judicial scholars.

> Should a company operating at a loss even on the prudent-investment basis be denied permission to discontinue service, so that in effect its property is actually being confiscated for the public use without just compensation, the minority [in FPC v. Natural Gas Pipeline (1942)], in refusing to discuss the question, would be hard put to avoid the explicit language of the Fifth Admendment. Of course, the minority answer would probably be that the Commission would not make such an order unless based upon appropriate findings, for which there would be the safeguard of adequate review.[44]

However, as the subsequent decision in the Hope case revealed, a majority of the Court was not yet ready to articulate a valuation method of any specific sort--prudent investment included:

> ...it is the result reached not the method employed which is controlling....[i]t is not the theory but the impact of the rate order which counts,....[i]f the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the [Natural Gas] Act is at an end.[45]

The uncertainty of valuation and the status of the prudent investment concept during this period have been discussed extensively in light of the many state court cases decided then.[46]

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[44]"Public Utilities--Constitutional Law-Scope of Judicial Review of 'Confiscatory' Rate Orders," Note, 42 Columbia Gas Review 870, 873-874 (1942). See also, "Does the Ghost of Smyth v. Ames Still Walk?" Note, 55 Harvard Law Review 1116 (1942), for a review of rate cases in light of the then recent decision by the Supreme Court in FPC v. Natural Gas Pipeline, supra.

[45]Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 602 (1944).

[46]Mendelson, "Smyth v. Ames in State Courts, 1942 to 1952," 37 Minnesota Law Review 159, 164-165 (1953).

One assessment of the valuation rules and the status of the concept of prudent investment demonstrated the interpretative difficulty encountered by the state of Wisconsin:

> [One Wisconsin Court concluded that its state commission in a rate case]...found nothing except that a certain amount of dollars represent a reasonable profit.
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> ...Reasonable profit ON WHAT? That is the trouble with the commission's decision. It has no bottom. It has a numerator but no denominator. For a long time, Wisconsin believed in the "prudent investment" theory of rate making. A utility was entitled to a fair return on the amount of money prudently invested in the enterprise, it was said. That sounded fair. That is the universal standard. Every businessman expects to receive a fair return on the money which he has put into his business whether he runs a hardware store or an apartment building or a bowling alley. Our Supreme Court of Wisconsin approved the prudent investment theory.
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> ...Apparently many other Commissions and jurists interpreted the Hope case as [returning to the prudent investment theory]...for there was a great swing throughout the country to the investment cost theory in the years immediately following.[47]

There is little doubt that the concept of prudent investment has figured significantly in the Supreme Court's historical efforts to come to grips with the constitutionally controlling scheme of valuation for the purposes of utility ratemaking. But despite the fact that the prudent investment concept has received explicit minority approval as a possible regulatory approach under today's result-oriented constitutional standards of confiscation, the fact remains that the concept has never been given express majority approval by the U.S. Supreme Court. Prudent investment has not achieved the status of definitively resolving the conflict between historical costs and reproduction costs for which it was originally intended. This is because it never really spoke clearly to the issues surrounding that conflict. Instead, it has become, in a modern sense, exactly what it was originally: a concept useful in determining what facility costs should be allowed, rather than how costs for specific

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[47]Demet and Demet, "Legal Aspects of Rate Base and Rate of Return in Public Utility Regulation," 42 Marquette Law Review 331, 335-336 (1959).

facilities should be calculated. Viewed as a measurement of the inclusion of certain costs in the rate calculation because of the soundness of their incurrence, the concept has flourished as a regulatory oversight tool helpful to ratemaking regulators.

The status of prudent investment as a valuation methodology different from historical or reproduction costs is often inaccurately characterized. For example, in the widely read textbook on Public Utility Economics, by Paul J. Garfield and Wallace F. Lovejoy, it is observed that:

> [An]...actual cost method, called prudent investment, may be taken as historical cost, as defined, less any amounts found to be dishonest or obviously wasteful. Under the prudent investment standard every investment is assumed to be prudent unless the contrary is shown.[48]

While this characterization is generally true, it inflates prudent investment to the status of a rate methodology, rather than more accurately describing it as a test of what costs to include in the rate calculation.

But even as a criterion for the determination of what costs, whether actual or reproduction costs, of utility investment to include in rate-making decisions, the concept of prudent investment continues to be articulated abstractly by lower courts, leaving broad discretion for the application of the concept by regulators to specific investment decisions.

Current Legal Use of Prudence

The concept of prudence has found current application in several diverse areas of law. There are several recent lower court decisions that have referred in one fashion or another to obligations of the prudence of management decisions in regulated industries. It might be observed that in these cases the use of the concept of prudent investment or prudence

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[48]Paul J. Garfield and Wallace F. Lovejoy, Public Utility Economics (Eastcliff, N.J.: Prentice-Hall, 1964), p. 57.

generally is not encumbered by the baggage of the Brandeis valuation concept. Instead, the idea of prudent activities takes on an evaluative aspect concerning the propriety of decisions and their regulatory consequences.

For example, in a case involving the disallowance of various costs in airline rates relating to an employee strike, one court made this observation:

> But the issue is not whether the company acted lawfully but whether it acted prudently--a higher standard. The contract and the Railway Labor Act, also invoked by TWA, may well have given TWA the right to spend its won funds without limit in implementation of the attitudes of management. But they do not give TWA a right to a subsidy to cover losses in a strike prolonged by its imprudent intransigence, and that is the critical finding before us....
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> ...The [Civil Aeronautics] Board in no way assumed that prudence in taking account of human emotions required abject submission to labor demands.
>
> TWA charges that the Board was invading the sphere of management and was taking advantage of hindsight to hold management to an exceptional standard of conduct....In this respect the standard is not fundamentally different from that applicable in conventional utility rate regulation where the commission may disregard waste and improvidence but must not usurp the role of management....We seek to conjoin the spark of private profit and the drive of private enterprise with some surveillance by Government officials devoted to the public interest....That a conclusion of imprudence reflects a view of how business should be conducted is no reason for a court's withholding deference from permissible findings of the commissioners whose presumptively broad gauge warranted their appointment by the President, with the advice and consent of the Senate, to undertake the delicate task of surveillance of the regulated industry....
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> ...We are not unaware that the difficulties may be greater in practice than in philosophy in avoiding an improper usurpation of managerial discretion while conducting a proper review of abuse of that discretion, and that the difficulties are not lessened when Government officials have the 20-20 vision of hindsight. The greater risk of disallowances is doubtless noticeable even in conventional rate-making when the period under consideration is past and the commission proceeds by reference to actual operating figures rather than nunc pro tunc estimates.

> The other side of the coin is that in some instances utilities may gain the benefit of pointing to an adverse change in conditions more readily sensed by management than Government officials.[49]

The TWA case is important, not only for the principles set forth in evaluating managerial decision making, but also because it constitutes the only obvious example of judicial acknowledgement of the fact that the regulatory evaluation of prudence is retrospective. Yet the Court in TWA concluded that even as a retrospective regulatory tool, the evaluation of prudence served a valuable purpose.

Similarly, one U.S. Court of Appeals, in the context of reviewing the regulatory treatment to be accorded tax decisions made by regulated companies under the Natural Gas Act, assessed managerial discretion in relation to regulatory objectives in the following fashion:

> We freely recognize, as does the Commission, that there are many areas and many situations which must remain within the jurisdiction of management. However, it has long been recognized that establishment of public utility charges involves the assessment of costs for a public service. Basic to the purpose of the Natural Gas Act is a design of regulation concerned with final adoption of rate charges fairly intended to protect the public interest.
>
> Necessarily, the area of tax policies embraces managerial decisions directly reflected in the cost of natural gas supplies for the use of the ultimate customer. Here it seems to us quite reasonable and logical to recognize as inherent in the Commission the duty and requirement to exercise its expertise in evaluating the entire tax effect of managerial judgment. If such elected tax policies do not fairly indicate a reasonable and prudent business expense, which the consuming public may reasonably be required to bear, following the required hearing and review procedures, then federal regulatory intervention is required.[50]

The concept of prudence has even been used in evaluating the propriety of conduct relating to the environment. In Wayne County Dept. of Health,

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[49]Trans World Airlines, Inc. v. Civil Aeronautics Board, 385 F.2d 648, 655-657 (D.C. Cir. 1967), cert. denied 390 U.S. 944 (1967).

[50]Midwestern Gas Transmission Company v. Federal Power Commission, 388 F.2d 444, 448 (7th Cir. 1968), cert. denied 392 U.S. 928 (1968).

Air Pollution Control Division v. Olsonite Corp.,[51] a state court recently held that, for the purposes of an environmental protection statute, a provision that a defendant against whom action is brought pursuant to the statute may raise affirmative defense that there was no feasible and prudent alternative to the defendant's conduct, the words "prudent alternative" did not require that there be a comprehensive balancing of competing interests.

Thus the concept of prudence as a standard against which regulated activities can be evaluated has been used in a variety of contexts. In the broadest of legal uses, the adjective "prudent" is used so often in connection with judgment that it has become a regular term of legal art. But its use as an adjective does not necessarily invoke the definitional attempts of Brandeis in the context of utility ratemaking.

Law Relating to Oil and Gas Leases

The frequent use of prudence in connection with various judgmental legal evaluations occurs in several major areas of business conduct. One of the areas in which the concept has gained extensive use, and in which it has taken on major definitional significance, is the area of oil and gas leasing.[52]

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[51]Wayne County Dept. of Health, Air Pollution Control Division v. Olsonite Corp., 263 N.W.2d 778, 797, 79 Mich. App. 668 (1977).

[52]See generally Lopez and Parsley, "Microbes, Simulators, and Satellites: The Prudent Operator Pursues Enhanced Recovery under the Implied Covenants," 58 North Dakota Law Review 501 (1982); Williams, "Implied Covenants in Oil and Gas Leases: Some General Principles," 29 University of Kansas Law Review 153 (1981); Williams, "Implied Covenants for Development and Exploration in Oil and Gas Leases--The Determination of Profitability," 27 University of Kansas Law Review 443 (1979); Merrill, "The Modern Image of the Prudent Operator," 10 Rocky Mountain Mineral Law Institute 107 (1965); Meyers, "The Covenant of Further Exploration: A Comment," 37 Texas Law Review 179 (1958); Meyers, "The Implied Covenant of Further Exploration," 34 Texas Law Review 553 (1956); Merrill, "Implied Covenants and Secondary Recovery," 4 Oklahoma Law Review 177 (1951); and Merrill, "Implied Covenants, Conservation and Unitization," 2 Oklahoma Law Review 469 (1949).

The concept of the prudent operator requirement with respect to oil and gas leasehold development obligations was recently summarized in a legal treatise as follows:

> All jurisdictions impose a prudent operator rule to determine whether lease development satisfies the implied covenant of further development. This rule requires that operations be mutually profitable to both lessor and lessee and be diligently prosecuted in relation to the circumstances in each case. Within such relationship the lessee has an implied duty, after production is acquired, to develop the lease to its fullest extent.
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> By prevailing view, in Oklahoma, Texas, and several other jurisdictions, it is not a breach of the prudent operator standard when the lessee holds portions of a lease for long periods of time without development, where profitability of further development cannot be shown.[53]

This summary of the prudent operator test is based upon numerous state court decisions which have applied the rule in various specific disputes over the propriety of development decisions. The prudent operator rule as it is applied has squarely placed in courts the position of interpreting lease obligations by evaluating the factual circumstances relating to development, exploration, and recovery opportunities and decisions concerning specific leaseholds.

For example, in Trust Company of Chicago v. Samedan Oil Corp.,[54] the Tenth Circuit defined the prudent operator test as follows:

> ...the prudent operator [of oil and gas leases] test as the term suggests...imposes upon the lessee the implied duty to do whatever in the circumstances would be reasonably expected of a prudent operator of a particular lease, having a rightful regard for the interest of both the lessor and the lessee....[T]he implied covenants of the lease impose no obligation upon the lessee to develop the lease beyond the point where it would be profitable to him, even if some benefit to the

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[53]Richard W. Hemingway, The Law of Oil and Gas (St. Paul: West Publishing Co., 1983), Sec. 8.3., p. 414.

[54]Trust Company of Chicago v. Samedan Oil Corp., 192 F.2d 282, 284 (10th Cir. 1951).

lessor would result therefrom. And, that the one seeking cancellation has the burden of proving that the drilling of additional wells would probably result in profitable production.

The prudent development rule is clearly one of reasonableness. The Texas Supreme Court concluded in Clifton v. Koontz[55] that the lessee's obligation as to the development is measured by the rule of reasonable diligence or what an ordinarily prudent and diligent operator would do and does not require the continuation in the performance of these duties unless there is a reasonable expectation of profit, not only to the lessor, but also to the lessee.

Similarly, in Harris v. Morris Plan Co.,[56] it was held that a breach of the covenant to develop occurred when a well was abandoned and others were willing to enter and drill and there were several surrounding productive wells. In contrast, the decision in Baker v. Collins,[57] that a covenant to develop further was not breached when the existing well involved the expenditure of large sums of money and other wells that had been drilled were dry or not producing, again demonstrates the balanced judicial application of the rule.

And finally a pair of cases demonstrates an outer boundary on the requirements that will be imposed in the name of prudent development obligations. The cases held that where a lessee had made a substantial investment in exploration of the area and in drilling other wells to determine the advisability of further drilling on the leases or of drilling to deeper formations, there was no breach of the covenant of reasonable development.[58]

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[55]Clifton v. Koontz, 160 Tex. 82, 325 S.W.2d 684 (1959).

[56]Harris v. Morris Plan Co., 144 Kan. 501, 61 P.2d 901 (1936).

[57]Baker v. Collins, 29 Ill.2d 410, 194 N.E.2d 353 (1963).

[58]See, Frazier v. Justiss Mears Oil Co., 391 So.2d 485 (La. App. 1950), writ refused 395 So.2d 340 (La. 1950); and West v. Sun Oil Co. 490 P.2d 1073 (1971).

Recently in Mitchell v. Amerada Hess Corp., the Oklahoma Supreme Court made the important observation that profit can not be ignored as a component of the prudent operator requirement in a decision to add an additional well to a productive formation by holding:

> We thus hold there is no implied covenant to further explore after paying production is obtained, as distinguished from the implied covenant to further develop. In addition to the speculative burden the offered covenant would place on lessees, the covenant as tendered is substantially served by the covenant for further development as it is interpreted in this jurisidiction while limiting the duty to drill additional wells to those instances where a prudent operator would expect a probability of potential profit from the well contemplated.[59]

In U.S. v. City of Pawhuska,[60] the Tenth Circuit held that the prudent operator rule, as applied in Oklahoma, imposes an implied duty on a lessee to do whatever in the circumstances would be reasonably expected of a prudent operator of a particular mineral lease, having a rightful regard for interest of both the lessor and lessee.

The Kansas high court found in Rush v. King Oil Co.[61] that under the prudent operator test, which determines the scope of duties of oil and gas lessees, a lessee must continue reasonable development of leased premises to secure oil for common advantage of both lessor and lessee and the lessee may be expected and required to do that which an operator of ordinary prudence would do to develop and protect the interests of parties.

The prudent operator test provides a legal standard that requires continued examination of factual circumstances in order to assess prudence. New recovery and exploration techniques may create development and exploration obligations that did not exist in the past. In this respect, the

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[59]Mitchell v. Amerada Hess Corp., 638 P.2d 441, 449-450 (Okla. 1982).

[60]U.S. v. City of Pawhuska, 502 F.2d 821 (10th Cir. 1974).

[61]Rush v. King Oil Co., 556 P.2d 431, 220 Kan. 616 (1977).

prudent operator standard is sufficiently flexible to permit adaptation to changing circumstances.[62]

Finally, the obligation of prudent development has been applied as a standard governing mineral leases other than oil and gas. With respect to coal, one court has held that the rule that mining and selling coal be conducted in an ordinarily "prudent and businesslike manner" required merely whatever would be reasonably expected of operators of ordinary prudence, having regard to interests of lessor and lessee. Under such provision, no obligation rests on lessee to carry operations beyond the point where they will be profitable to them, even if some benefit to lessor will result therefrom. It is only to the end that minerals be extracted with benefit to both that reasonable diligence is required. Whether in any particular instance such diligence is exercised depends upon a variety of circumstances, such as quantity of coal capable of being produced from premises, local market or demand therefore, means of transporting it to market, and usages of business.[63]

Thus, the judicial development and use of the prudent operator rule as it is applied to the development, exploration, and recovery obligations attaching to oil and gas leaseholds bear direct analogy to the usage of the prudent investment concept as it relates to public utilities. One significant difference that is worthy of note, however, is that the concept of prudent development obligations gives rise to affirmative injunctive relief by the courts. If prudent development is not occurring and it should be, it can be directed by the courts or penalties extinguishing leasehold rights may be imposed. Viewed from the perspective that a failure to undertake additional development of a leasehold is a continuing negative

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[62]See Lopez and Parsley, "Microbes, Simulators, and Satellites," p. 501.

[63]See, Mendota Coal & Coke Co. v. Eastern Ry. & Lumber Co., 53 F.2d 77 (9th Cir. 1931).

development decision, the prudent operator test may contain the same retrospective component as the prudent investment requirement applied to public utilities.

Law Relating to Trusts

There is at least one other major area of law in which the use of the prudent investment concept bears a striking similarity to the use of that concept in connection with public utilities. Although there does not appear to be a traceable origin of the use of the concept of prudent investment respecting public utilities from the concept of prudent investment pertaining to trust obligations, it does seem fair to assume that the long standing use of the concept in trust law would have been known to, and could have been borrowed by, legal scholars--including Brandeis--who played a role in the early articulation of prudent investment theory for public utilities.

As the trust concept of the prudent investment was described in one leading case, decided by the Massachusetts Supreme Court in 1890:

> The rule in general terms is that a trustee must in the investment of the trust fund act with good faith and sound discretion, and must "observe how men of prudence, discretion, and intelligence manage their own affairs, not in regard to speculation, but in regard to the permanent disposition of their funds, considering the probable income, as well as the probable safety of the capital invested...."
> A prudent man possessed of considerable wealth, in investing a small part of his property, may wisely enough take risks which a trustee would not be justified in taking. A trustee, whose duty it is to keep the trust fund safely invested in productive property, ought not to hazard the safety of the property under any temptation to make extraordinary profits. Our cases, however, show that trustees in this Commonwealth are permitted to invest portions of trust funds in dividend paying stocks and interest bearing bonds of private business corporations, when the corporations have been acquired, by reason of the amount of their property and the prudent management of their affairs, such a reputation that cautious and intelligent persons commonly invest their own money in such stocks and bonds as permanent investments.[64]

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[64]Appeal of Dickinson, 152 Mass. 184, 25 N.E. 99, 99-100 (1890).

Similarly, in another case, St. Louis Union Trust Co. v. Toberman, the court provided a broad description of the duties of a trustee:

> As a fundamental proposition, it is the duty of a trustee, in the investment of trust funds committed to his care and keeping, to exercise such care and diligence as men of ordinary prudence, intelligence, and discretion would employ, not with a view to speculation, but rather with a view to the permanency of the investment, considering both the probable income and the probable safety of the capital invested. This does not mean, however, that a trustee shall invariably have the unlimited authority to invest trust funds as an ordinarily prudent and diligent man might invest his own funds, since an ordinarily prudent man may, and frequently does, invest his own funds with the idea and hope of accumulation, and at the risk which such intent imposes. A trustee, on the contrary, may take only such risks as an ordinarily prudent man would take in the investment of the funds of others, bearing ever in mind that it is the preservation of the estate, and not an accumulation to it, which is the chief object and purpose of his trusteeship.[65]

In fact the very nature of a trust is almost completely dependent upon the judicial oversight provided by the concept of prudent investment decisions made by the trustees acting on behalf of beneficiaries.

Clearly, the risks of concentration and benefits of diversification are accepted rules of prudent trust management under the prudent investment rule.[66] It has been held, for example, that trustees failed to follow the prudent investor standard with respect to administration of a testamentary trust of which the plantiffs were beneficiaries where they invested two-thirds of trust principal in a single investment, invested in real property secured only by a second deed of trust, and made that investment without adequate investigation of either borrowers or collateral.[67]

But as broadly articulated in Jackson v. Conland,[68] the prudent

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[65]St. Louis Union Trust Co. v. Toberman, 235 Mo. App. 559, 140 S.W2d 68,72 (1940).

[66]See, Dowsett v. Hawaiian Trust Co., 393 P.2d 89, 95, 47 Haw. 577 (1964).

[67]Matter of Collins' Estate, 139 Cal. Rptr. 644, 72 C.A.3d 663 (1977).

[68]Jackson v. Conland, 420 A.2d 898, 178 Conn. 52 (1979).

investor rule, which is the usual touchstone for evaluating the propriety of trust investments, requires that the trustee observe how men of prudence, discretion, and intelligence manage their own affairs, not in regard to speculation, but in regard to permanent disposition of their funds, considering the probable income, as well as the probable safety of the capital to be invested.

Legal obligations of prudence similar to those employed in relation to the duties of trustee are also used in law relating to the administration of estates. The obligation in estate administration has been summarized this way:

> A fiduciary is required to exercise reasonable care and skill and to act prudently in the performance of his functions. The standard of care and skill is expressed in various ways....Modern cases often quote the language of Professor Scott and the Restatement, which provide that a trustee is to exercise "such care and skill as a man of ordinary prudence would exercise in dealing with his own property." 1 Restatement of Trusts Second Sec. 174; 2 Scott, Trusts Sec. 174 (2d ed. 1956). The element of prudence--the caution implicit in this standard--is frequently emphasized by stating that the test is not how a prudent man would act with regard to his own property but how a prudent trustee would act in administering the property of others or how he would act in conserving property.
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> In re Mild's Estate, 25 N.J. 467, 136 A.2d 875 (1957), involved the surcharge of an administratrix for delegation of duties and failure to supervise the activities of her attorney. To the assertion that the administratrix was not capable of adhering to the usual standard of care and skill, the court responded: "This standard does not admit of variation to take into account the differing degrees of education or intellect possessed by a fiduciary. The standard of the ordinary prudent person is of necessity an ideal one and is not tailored to the imperfections of any particular person." Mr. Justice Holmes aptly stated the rule as follows:
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> "The standards of the law are standards of general application. The law takes no account of the infinite varieties of temperament, intellect and education which make the internal character of an act so different in different men. It does not attempt to see men as God sees them, for more than one sufficient reason...." Holmes, The Common Law, p. 1089 (1881)....
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> On the other hand, a fiduciary possessing greater than ordinary skill and more than ordinary facilities is under a duty to exercise the skill and to utilize the facilities at his disposal. Thus in Liberty Title & Trust Co. v. Plews, 142 N.J.Eq. 493, 509, 60 A.2d 630, 642 (1948), it is stated:

> "In the present case, the corporate trustee held itself out as an expert in the handling of estates and trust accounts. It also held itself out as having particular departments for investments and statistical information, and especially skill in this respect. It had so advertised for a number of years....It therefore represented itself as being possessed of greater knowledge and skill than the average man and, '...if the trustee possesses greater skill than a man of ordinary prudence, he is under a duty to exercise such skill as he has.'...The manner in which investments were handled must be viewed and assayed in the light of such superior skill and ability."[69]

There are several ways in which the courts have expressed the concept of prudent action in regard to the administration of trusts and wills. For example, the case of In re McCafferty's Will[70] held that executors must "be faithful," "diligent," and "prudent" and exercise industry and care as intelligent men exercise in the conduct of their own affairs of equal importance.

The broad legal principles imposing prudence in the managment of trusts and estates necessarily draw courts into the examination of specific investments.[71] Although the prudent man rule requires in each case the assessment of the prudence of managerial actions, over the years courts have come to identify certain types of investments as inherently imprudent because of the high degree of risk associated with them. However, the legal test for prudence continues to provide the flexibility for a continuing reassessment of the soundness of various investment options. For example, one commentator recently observed that the historical legal view of trust investment in common stocks as being imprudent might be changing:

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[69]Eugene F. Scoles and Edward Halbach, Jr., Decedents Estates and Trusts (Boston: Little, Brown and Co., 1965), pp. 473-474.

[70]In re McCafferty's Will, 264 N.Y.S. 38, 147 Misc. 179 (1933).

[71]See generally, Shattuck, "The Development of the Prudent Man Rule for Fiduciary Investment in the United States in the Twentieth Century," 12 Ohio State Law Journal 491 (1951); and Bines, "Modern Portfolio Theory and Investment Management Law: Refinement of Legal Doctrine," 76 Columbia Law Review 721 (1976).

> Regarding the prudent man rule, the investment strategy suggested by modern theory appears to run afoul of many of the established principles of trust investment law. Yet, the market portfolio [of common stocks] has been recommended by some of the most skilled experts in the field of trust investments. When the market portfolio is finally tested under the prudent man rule, courts should adopt a position consonant with modern theory. The beauty of the prudent man rule is that "[i]t is susceptible of being adapted to whatever conditions may arise in the evolution of society and the progress of civilization." [Footnote deleted.][72]

Like the area of oil and gas leasehold developmental obligations under the prudent operator rule, the prudence legally required in the operation of a trust is directly analogous to the concept of prudent investment requirements in the area of utility regulation. In trust law, the concept of prudence has both prospective and retrospective significance. It can be used to impose subsequent liability for imprudent decisions of the past, as well as impose an injunctive remedy to force decisions to be made in the future.

Implicit in both the areas of oil and gas leasing and trusts is the notion that appropriate conduct is governed by a high duty of management care because the legal control of management decisions has been vested with those other than the direct beneficiaries. What is prudent is deemed to be ascertainable through the reasonable efforts of competent managers with sound and reasonable judgment. That risk is involved in managerial decison making is judicially acknowledged. But, the deliberate exposure to substantial risk in the exercise of managerial discretion is by its very nature imprudent, for risk is to be avoided, if not altogether, at least insofar as possible under the circumstances.

Federal Natural Gas Legislation

In the debate over federal natural gas regulation, the 98th Congress (1984) recently focused on the concept of prudence in an effort to address concerns over the natural gas acquisition practices of interstate natural

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[72]Weil, "Common Stock: The Forbidden Trust Investment," 33 Alabama Law Review 407, 435 (1982).

gas pipelines. Although no action was taken by the Congress, the debate over these practices is likely to continue. The focus of debate is the provision contained in Section 601(c) of the Natural Gas Policy Act of 1978,[73] which permits the automatic pass-through of gas acquisition costs by pipelines to distribution companies unless the Federal Energy Regulatory Commission finds "...the amount paid was excessive due to fraud, abuse, or other similar grounds."

Shortly after the enactment of the NGPA, pipelines entered into new gas purchase contracts which often contained so-called "take-or-pay" provisions.[74] Take-or-pay provisions have often been identified as one of the reasons that delivered prices to consumers remain high, despite excessive supplies and diminishing demand. But one rate proceeding in particular had the effect of focusing attention on the "fraud, abuse, or other similar grounds" provision of the NGPA.

On December 30, 1982, Federal Energy Regulatory Commission Administrative Law Judge Levant announced a decision concerning the purchased gas adjustment rate--the pass-through rate--for Columbia Gas Transmission Corporation, a pipeline with production and distribution subsidiaries serving Ohio, Kentucky, West Virginia, and Washington, D.C., among other states. Judge Levant made two key findings: first, that Columbia's contracting practices prevented it from discharging its legal obligation to sell gas at the lowest reasonable rate, and second, that Columbia had reduced "takes" of lower cost gas in order to continue "takes" of high cost gas, frequently from its own subsidiaries. These two findings, along with others, formed the basis for concluding that Columbia's purchasing practices constituted an "abuse" under Section 601 and that the pass-through should be denied.[75]

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[73] 15 U.S. Code Section 3301, et seq.

[74] See Poling, "The Natural Gas Dilemma: Decontrol or Recontrol?" 30 Federal Bar News & Journal 206 (April 1983).

[75] See, Columbia Gas Transmission Corp., F.E.R.C. Docket Nos. TA 81-1-21-001 and 81-2-21-001, Decision of the Administrative Law Judge (Dec. 30, 1982); and F.E.R.C. Opinion No. 204 (Jan. 16, 1984).

While the Levant decision was pending for final decision by the Commission, the Congress began to debate in earnest proposed natural gas legislation. FERC's review of the Columbia case rejected the conclusion that an "abuse" under the NGPA had occurred, even though the Commission found without apparent legal significance that Columbia "recklessly disregarded" its legal mandate to provide gas at the lowest possible cost to its customers.[76]

Hearings and studies available to the Congress had identified take-or-pay contracts as one impediment to effective market signalling between producers and ultimate consumers.[77]. Among various legislative proposals were specific proposals which would have modified the Section 601 "fraud and abuse" provision by adding the concept of prudence. As the legislation developed, first, by the Senate Energy Committee and later by the House Energy and Commerce Committee, both versions contained prudence modifications of Section 601 (among many other elements).

The Senate Energy Committee adopted a "prudent purchase rule," which allowed pass-through of certain gas acquisition costs in relation to the formulated "free market price indicator." This approach was summarized as follows:

> Section 301 would amend section 601(c) of the NGPA by adding three new paragraphs. Section 601(c) currently provides, in part, that the Federal Energy Regulatory Commission may not prohibit an interstate pipeline from recovering from its customers the ful [sic] cost of the gas it has purchased, unless the Commission determines that the pipeline paid an excessive amount for such gas due to fraud, abuse, or similar grounds. In the absence of such a finding, the Commission is required to permit each pipeline to pass through to its customers its purchase gas costs, if such costs are deemed to be just and reasonable under section 601(b).

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[76]See Poling, "Natural Gas: 1983 Events," 31 Federal Bar News & Journal 82 (February 1984)

[77]See, "Natural Gas Regulation Study," (Committee Print 97-GG), Subcommittee on Fossil and Synthetic Fuels of the House Committee on Energy and Commerce, 97th Cong., 2d Sess. (1982).

Section 301 would add a "prudent purchase" test to the requirements of section 601(c). The test would apply only to gas purchased under contracts for the first sale of natural gas entered into or renegotiated during a three-year period after the date on which the free market price indicator goes into effect. That date would be the first day of the eighth full month after enactment of the bill.

In general, the prudent purchase test would establish new standards to be applied by the Commission in determining whether interstate pipelines would be permitted to pass through to their customers certain increases in purchased gas costs.

New paragraph (3) of section 601(c) would permit the passthrough of purchased gas costs if the amounts paid are "prudent" as defined in subparagraph (A). However, the Commission would have the authority to prohibit a pipeline from recovering purchased gas costs that do not meet the prudency test. Passthroughs could not be denied if such purchases are "prudent" as defined in subparagraph (A). Purchases would be deemed to be prudent if they meet one of three criteria: (1) the weighted average amount paid during any month for gas purchased under new and renegotiated contracts does not exceed 110 percent of the free market price indicator in effect during that month; (2) the purchase is the result of a pipeline's exercise of right of first refusal pursuant to section 318(a); or (3) the amount was paid pursuant to a right of first offer under section 318(b).[78]

In his "Minority Views," Senator Metzenbaum put it more simply:

To summarize, the problem the Senate should address is the failure of pipelines to minimize their gas costs. Pipelines have not only passed up cheap supplies in favor of expensive supplies, and agreed to prices and price formulas which are exorbitant, but they have entered into long-term contractual arrangements which have impaired their ability to respond to market changes. At a minimum, effective consumer legislation would not only require that pipelines engage in prudent purchase gas practices and be held accountable to the customers for their imprudence, but would also void the overbearing contractual provisions, which prevent pipelines from lowering their gas costs. Ceilings must be placed on take-or-pay obligations, and price escalation clauses must be defused.[79]

The House Committee on Energy and Commerce took a very different approach from the Senate Energy Committee in its adoption of a prudence

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[78]Senate Report 98-205, 98th Congress, 1st Session (1983), at p. 32.

[79]Id., at p. 154.

standard as a part of the existing section 601 of the NGPA:

> Section 301(a) amends section 601(c) of the NGPA by adding paragraphs (3) and (4) thereto. The new NGPA section 601(c)(3) defines the term "similar grounds," thereby amplifying this basis for denying the "passthrough of pipelines" purchase gas costs to consumers. "Similar grounds" includes misrepresentation (by the pipeline purchaser); imprudence by a pipeline in its gas purchasing practices, including any purchasing or operating practice which does not result in the lowest reasonable rate; and failure by a pipeline to bargain at arm's-length with any natural gas seller. In determining whether a rate is the lowest reasonable rate, the Commission should look not only at the level of prices paid producers for gas but should also consider other factors relevant to maintenance of adequate service, such as reliability and location of supply, the need for long-term commitments of reserves, and the operating characteristics of the pipeline, all of which affect the value to the pipeline of particular supplies.[80]

In the "Additional Views," subscribed to by twenty members of the Committee, this characterization was also given of the Committee approach:

> Section 302 of H.R. 4277 would direct FERC to deny recovery of natural gas purchase costs incurred by interstate pipelines in cases of misrepresentation, imprudence, "including any purchasing or operating practice which does not result in the lowest reasonable rates," or a failure to bargain at arm's length. Pipelines are also prohibited from providing "any undue preference or advantage to any affiliate." The Commission may not, however, use this authority to establish natural gas ceiling prices or set forth any price ("or method of determining such a price") as a dividing line between prudent and imprudent prices.
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> If the FERC finds that a pipeline has been imprudents [sic], has unreasonably refused to provide transportation services, or has discriminated in favor of an affiliate in providing transportation services, FERC shall make "an appropriate reduction" in the pipeline's rate of return.[81]

Thus, it can be seen that the approaches taken by the House Committee and the Senate Committee were quite different. The Senate approach was one

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[80]House Report 98-814, 98th Congress, 2d Session (1984), at p. 40.

[81]Id., at 139.

wholly of statutory construct. The use and definition of "prudent" was undertaken in specific and limited reference to a statutory scheme of rate formulation and is clearly not an effort to incorporate judicial uses of the concept of prudence for the discretionary use of ratemakers. The rates would have been set by formula, with little or no regulatory application of standards of prudence as a review of the soundness of utility management investment decisions.

The House approach appears to have been an effort, in part, to vest regulatory discretion by lifting the usage of prudence from the law generally without the imposition of a strict statutory definition.

The possible renewal and ultimate outcome of the recent Congressional debate over modifications to the Natural Gas Policy Act is in doubt. There is substantial public concern over the many aspects of the natural gas industry. The proposed legislation had the effect of focusing attention on, and renewing the discussion of, the concept of prudent business practices by natural gas companies.

It is fair to observe that, although federal regulation of natural gas under the Natural Gas Act and the Natural Gas Policy Act has not extensively utilized heretofore the concept of prudence (as it is summarized here), the concept is not foreign to federal regulation and has been used from time to time. For example, in a Court of Appeals decision in one of the Permian Area Rate Base cases, it was observed that the return of a public utility should assure confidence in the financial soundness of the utility and be adequate under prudent management to maintain and support its credit and enable it to raise money necessary for proper discharge of its public duties.[82]

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[82]See Skelly Oil Co. v. Federal Power Commission, 375 F.2d 6 (10th Cir. 1967), affirmed in part, reversed in part, Permian Basin Area Rate Cases, 390 U.S. 747 (1968), rehearing denied Bass v. Federal Power Commission, 392 U.S. 917 (1968).

On the other hand, the Federal Power Commission, predecessor of the Federal Energy Regulatory Commission, held that regulated utilities had extensive management discretion in the conduct of business affairs:

> The Commission has no authority either to conduct or supervise the day-to-day operations involved in the production and transportation of natural gas in interstate commerce. Those functions are left to management for decision and the managers exercise a broad area of discretion in the conduct of business.[83]

Still, the Court of Appeals in the Midwestern Transmission case, supra, did refer to "prudent business expenses." Thus, the references to prudent action under federal natural gas regulation have been made, although the regulatory concept has not received specific endorsement as a method of disqualifying investments from eligibility for inclusion in the rate base.

In fact, one effort by the FERC to establish a rule requiring producers to act as prudent operators in developing and maintaining deliverability from natural gas reserves was found to be beyond the statutory authority of FERC under the Natural Gas Act. In Shell Oil Co. v. Federal Energy Regulatory Commission,[84] the Fifth Circuit held that the imposition of a prudent operator rule as an implied condition of natural gas company sales and transportation certificates was contrary to the prohibitions against the regulation of production and gathering under the Natural Gas Act. Shell only determined that the statute would not allow for the proposed regulation and did not attempt to assess the efficacy of the FERC proposed use of the prudent operator test. Although the current Congressional proposals concerning prudent operational activities by pipelines

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[83]Midwestern Gas Transmission, 36 F.P.C. 61, 70 (1966).

[84]Shell Oil Co. v. Federal Energy Regulatory Commission 566 F.2d 536 (5th Cir. 1978). See also, note, "Gas Law--The Federal Energy Regulatory Commission under Authority Conferred by the Natural Gas Act of 1938 is Exceeding Its Jurisdiction by Issuing Order No. 539B which Would Establish a Regulation Requiring a Producer to Act as 'Prudent Operator' in Developing and Maintaining Deliverability from Natural Gas Reserves," 6 Texas Southern University Law Review 481 (1981).

have a somewhat different focus from the FERC proposal dealt with in Shell, both attempted the use of prudence as a regulatory standard.

Congressional consideration of the use of prudence as a method to establish a regulatory standard of scrutiny over gas purchasing practices is significant. Under the current relaxed regulatory framework of the NGPA, where wellhead rate ceilings are set by statutory formula, the current pass-through provisions provide only modest regulatory flexibility in terms of "fraud or abuse." These terms, like prudence, are concepts of legal art. But their narrowness has limited the authority, or perhaps willingness, of the FERC to use them effectively. The statutory expansion of FERC discretion through the use of prudence is viewed as increasing the degree of regulatory scrutiny which may be exercised. Without an express statutory definition, the pending legislative proposals introducing prudence into the NGPA framework would seem to incorporate many of the views of prudence reviewed here.

CHAPTER 3

RECENT STATE APPLICATIONS OF THE PRUDENCE TEST

As indicated in chapter 1, there have been many state commission applications of the prudence test in recent years. In this chapter, we review the major cases by type of case. Before this, however, we offer certain guidelines for successful applications of the prudent investment test.

Guidelines for a Successful Prudence Application

In reviewing the many state utility commission inquiries that use the concept of prudence, we noticed certain themes that are common to many of the proceedings that treat this concept with special care. From these themes are derived four guidelines for proper use of the prudent investment test. These guidelines are not necessarily all explicitly delineated in any particular case.

In our view, the principal guidelines for a successful prudence inquiry are (1) a rebuttal of the presumption of prudence, (2) a rule of reasonableness under the circumstances, (3) a proscription against hindsight, and (4) a retrospective, factual inquiry. Following these guidelines is likely to be useful, perhaps necessary, for having a court sustain commission findings. However, because prudence is an evolving regulatory tool, following these guidelines may not be sufficient to guarantee that a commission's findings will be upheld. This is because regulatory tests other than prudence must also be considered.

The Presumption of Prudence

When applying the prudent investment test, state commissions have taken seriously Justice Brandeis' admonition regarding prudent investments: "Every investment may be assumed to have been made in the exercise of

reasonable judgment, unless the contrary is shown."[1] Commissions have interpreted this as requiring a rebuttable presumption of prudence. It has been held that without "affirmative evidence showing mismanagement, inefficiency, or bad faith,"[2] an investment decision is presumed to be prudent. In the absence of such an affirmative showing, at least one court has stated that a commission cannot disallow a utility's expenses.[3] Thus, for example, unless a particular management decision associated with the planning or construction of a power plant is challenged, the full original cost of the investment in the power plant is presumed to be prudent and includable in rate base.[4] The presumption of prudence makes for efficient regulation in that commissions are not required, or allowed, to review the prudence of all utility decisions regardless of their number, importance, or result.

A mere allegation of imprudence may not be sufficient to rebut the presumption of prudence; rather, an allegation of imprudence must be backed up by evidence that is substantive and that creates a serious doubt about the prudence of the investment decision.[5] A serious doubt as to the prudence of management decision making might be created, for example, by a Nuclear Regulatory Commission decision denying an operating license to a nuclear unit because of inadequate quality assurance or by a large, unexplained construction cost overrun.[6] In one state the mere existence

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[1]State of Missouri ex rel. Southwestern Bell Telephone Co. v. Public Service Commission, 262 U.S. 276, 289 (1923) Brandeis, J. concurring.

[2]Re Chesapeake & Potomac Telephone Co., 57 PUR3rd 1, 7 (D.C.P.S.C., 1964).

[3]State ex rel. Utilities Commission v. North Carolina Textile Manufacturers Association, Inc., 296 S.E.2d 487, 498 (N.C.Ct. App., 1982).

[4]Of course, in fair value states the investment is included in rate base at its fair value, which may or may not be its original costs.

[5]Minnesota Power and Light Co., 11 FERC Para. 61,312 (1980).

[6]See Randall L. Speck, "Proving Imprudent Management in Nuclear Power Plant Construction," a paper presented to the Seventh Annual Conference of Regulatory Attorneys (Madison, Wisconsin, June 4, 1984), p. 4.

of a construction cost overrun was considered enough to rebut the presumption of prudence.[7] However, another state commission rejected evidence challenging the presumption of prudence in a case where the construction costs of a nuclear power plant were claimed to be excessive on the basis of the costs for comparable units constructed elsewhere.[8] This indicates that one is more likely to create a serious doubt that serves to rebut the presumption of prudence if the evidence is closely related to the decisions about the plant in question.

Once the presumption of prudence has been rebutted, the utility has the burden of proving that the investment decision alleged to be imprudent was in fact prudent. Whether the utility actually meets its burden of proving that its decision was prudent depends on the test used for determining prudence and on the evidence presented for and against prudence.

Reasonableness under the Circumstances

When the rate base treatment of an investment is challenged on the basis of prudence, the test applied to determine if the investment decision is prudent becomes critical. Most commissions applying the prudent investment test use the standard developed in the Brandeis opinion of the Southwestern Bell case; namely, the prudence of a decision is based on its reasonableness under the circumstances.[9] From this starting point, state commissions have developed the prudent investment test as it is currently applied to public utilities. This test requires a standard of care (a fiduciary duty) owed by the utility to its customers. The standard of care is one of "reasonableness under the circumstances which were known at the

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[7]See In Re Detroit Edison Co., 24 PUR4th 326 (Mich. P.S.C., 1978).

[8]See In Petition of Florida Power Corp., [1979-81 Transfer Binders] Util. L. Rep. (CCH) Para. 23,318 FlaPSC, (1981). See also, Re Consolidated Edison Co. of New York 96 PUR 195, 231 (NYPSC, 1952), in which there was no exclusion from rate base where there was no specific proof of excessive costs for the plant in question, even though the construction costs of the plant were higher than those of comparable plants.

[9]See footnote 1, supra.

time."[10] This test was elaborated in a recent case before the Massachusetts Department of Public Utilities as follows:

> [A utility's] actions should be judged by asking whether they were prudent at the time, under all the circumstances, considering that the Company had to operate at each step of the way prospectively rather than in reliance on hindsight. Accordingly, the department will base its findings on how reasonable individuals would have responded to the particular circumstances and whether the Company's actions were prudent in light of all conditions and circumstances which were known or which reasonably should have been known at the time the decisions were made.[11]

Other tests for prudence have been considered. Some other tests look at the final outcome of a utility's decision in judging prudence. A utility may construct an inoperable generating station, may exceed its construction budget severalfold, or may incur costs much greater than the costs of another utility for constructing a similar plant. Under the guidelines we suggest here, these final outcomes may serve to overcome the presumption of prudence, but do not necessarily address the question of reasonableness under circumstances. In some instances, state commissions use some form of final outcome test for determining prudence, either as the only test or as a test that supplements the test of reasonableness under the circumstances.

Other tests for prudence have been proposed, but have been rejected by several commissions. The more lax "rational basis standard" would hold an investment to be prudent provided the manager's decision had some rational basis.[12] The only investment decisions that are likely to be rejected

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[10]Re Boston Edison Co., 46 PUR4th 431 (Mass. DPU, 1982).

[11]Id., p. 438.

[12]The rational basis standard was approved of in Re Consolidated Edison Co. of New York, 54 PUR3d 43, 112 (N.Y. PSC, 1964), aff'd 260 N.Y.S.2d 340 (1965), modified on other grounds 217 N.E.2d 140 (1960) (per curiam), but was later rejected in Re Consolidated Edison of New York, Inc., 45 PUR4th 325 (NYPSC, 1982).

under the rational basis test would be those that are either made with the intent of fraud or are totally irrational. Commissions also have rejected the "abuse of discretion" test[13] and the "normal business judgment" test, because these tests are inappropriate in that

> [W]e are not dealing...with suits against corporate officials for individual liability. We are concerned with the extent to which ratepayers should bear [the costs of an imprudent action, which cannot] be equated with the rules defining director's obligation to a corporation.[14]

In applying the standard of reasonableness under the circumstances, commissions, in some instances of high risk projects, have required a higher than normal standard of care to compensate for the high risks associated with project decisions. For example, in one FERC case involving a multi-billion dollar nuclear project, the administrative law judge held that no industry can be permitted to set its own standards by universally adopting careless and slipshod methods. In applying the reasonableness standard, it is thus no excuse that a utility did no worse than its peers; rather, the public has the right to demand the use of superior tools and techniques to build nuclear generating facilities at the lowest reasonable costs. When the risk of harm to the ratepayer is greater, the standard of care expected from a reasonable person is higher.[15] Because of the amount of skill, expertise, and experience necessary to complete a nuclear plant successfully, state commissions have sometimes held utilities to a very high standard of care when applying the test of reasonableness under the circumstances. For example, the New York

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[13]Used in Re Midwestern Gas Transmission Co., 36 F.P.C. 61, 70-71 (1966), aff'd 388 F.2d 444 (7th Cir.), cert. denied 392 U.S. 928 (1968).

[14]Re Consolidated Edison Co. of New York, Opinion 79-1 (NYPSC, January 16, 1979), p. 5.

[15]See New England Power Company, Docket No. ER8L-703-000 (FERC, per Nacy, A.L.J. May 4, 1984); see also Speck, "Proving Imprudent Management," p. 5.

Public Service Commission emphasized the high degree of care in planning, supervision, and control required in the construction of nuclear power plants due to the health risks associated with nuclear materials and the high cost that can result from error and delay.[16]

Proscription Against Hindsight

A proscription against the use of hindsight in applying the prudence standard is a corollary to the "reasonableness under the circumstances" test. The decisions of the utility are not subject to "Monday-morning quarterbacking." Instead, they are to be judged in light of the conditions and circumstances that were or should have been known to the utility at the time of its decision. In our view, the proscription against hindsight makes it unwise for a commission to supplement the reasonableness test with some form of final outcome test unless the final outcome test is used solely to overcome the presumption of prudence.

If a state commission engages in hindsight, any finding of imprudence is subject to reversal. One example of such a reversal involves a recent case before the Florida Supreme Court. The court reversed a decision by the Florida Public Service Commission that the Florida Power Corporation was imprudent in its management of its Crystal River-3 nuclear plant because the utility failed to check a hook, which failed, resulting in a 2,000 pound test weight falling onto some nuclear fuel assemblies. The court stated that the Commission had used hindsight in its decision.[17]

Retrospective, Factual Inquiry

Once the presumption of prudence is overcome, there is a need to

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[16]See Re Consolidated Edison Co. of New York, Opinion No. 79-1 (NYPSC, January 16, 1979).

[17]"State High Court Again Nixs PSC Order for $11-Million Florida Power Refund," Electric Utility Week, October 8, 1984, pp. 4-5.

develop evidence about whether the investment decision was prudent or imprudent. To accomplish this, state commissions engage in retrospective, factual inquiries.

Evidence for prudence or imprudence needs to be retrospective, or backward looking, in that it must be concerned with the time at which the decision was made. It must present facts, not merely opinion. These facts should cover all the elements that did or could have entered into the decision, including all relevant data, information, decision-making tools, and the circumstances at the time. For example, it would be improper to use past data in a current computer model to review a past decision if this type of model were not available in the past or if use of such a model could not reasonably be expected of the decision maker.

The evidence is presented in an inquiry before the commission. This may be a rate case that takes up the rate base treatment of a utility investment or a special prudence inquiry. In either case, the commission inquiry may be preceded by a staff investigation, which ought to be retrospective and factual, with a view toward developing the evidence for use in the inquiry. Such staff investigations can look at the past in great detail and therefore can be time-consuming and expensive, especially if much of the work is done by consultants.

Recent staff prudence investigations are similar in many ways to the prospective management audits that have been conducted in the 1970s and 1980s. A restrospective prudence investigation is different, however, from a management audit in one key aspect. The prudence investigation is backward looking without applying hindsight to decisions made in the past. A management audit, on the other hand, looks at the decisions of a utility, given contemporary management standards. Because it suggests changes in the utility's managerial practices to be made prospectively, the use of hindsight is not only allowed, it is encouraged.

Areas of Recent State Application

We have reviewed recent state commission prudence inquiries involving electric and gas utilities. Many electric applications were discovered but few gas applications. The two principal areas of application involving electric utilities were construction costs overruns and plant abandonments with capacity additions running a distant third.

Few of these cases rely solely on the prudence test for reaching a judgment. In most, the commission references the "used-and-useful" test or a "balancing of interests" test (that is, balancing the legitimate interests of customers and investors) to decide if certain costs should be included in rates. The cases described here in detail are those that rely most strongly on the prudence test. Those merely mentioned here all refer to the concept of prudence, but the degree to which the commission relied on this concept in reaching its decision was sometimes unclear. Also, some of the cases here rely on extensive staff prudence investigations for evidence.

Construction Cost Overruns

The prudence inquiries that rely most heavily on staff investigations are those involving generating plant construction cost overruns. This is so because the purpose is not simply to decide whether or not imprudent decisions were made, but also to determine the consequences of any imprudent decisions in terms of additional costs. Several state regulatory commissions have recently begun inquiries regarding the prudence of a utility in managing construction costs.

Because construction cost overruns rarely occurred before the 1970s, and when they did occur the overruns were of small magnitude, the authors found few cases explicitly applying the prudence test to construction cost overruns before the 1970s. Rather, the presumption of prudence applied. However, since the 1970s, state commissions have been more active in

challenging the value of investments about to go into rate base on the basis of prudence. Such a challenge usually must be preceded by a staff prudence investigation to develop evidence of imprudence.

Some key areas into which a staff investigation of cost overruns is likely to inquire are (1) whether decisions relating to costs were made at the appropriate levels within the corporate hierarchy and whether the senior officers received adequate information to allow them to make responsible decisions; (2) whether the utility was adequately involved in the planning of the project; (3) whether the utility selected an architect/engineer who could handle the project in a cost-effective manner; (4) whether the utility monitored the engineering effort; (5) whether procurement was based on competitive bids; (6) whether the contracts were all cost-plus, or whether there were incentive mechanisms included; (7) whether the utility monitored the work force utilization; (8) whether time schedules were established for construction tasks and whether there were adequate reporting systems in place to identify deviations from the schedule; (9) whether the scheduling was realistic and whether management used the reporting systems as a tool to prevent future delays; (10) whether delivery of materials and equipment were effectively scheduled, controlled, and monitored; (11) whether the construction manager was effectively monitored; (12) whether the utility took steps (especially in nuclear construction) to improve the interaction between construction and engineering; (13) whether there was adequate monitoring of the project budget and whether variances from the budget were brought to the attention of project management; and (14) whether the utility arranged its financial planning so that financing would not adversely affect scheduling, and hence cost. In addition, one could investigate key technical issues that deal with the competence of the design, engineering, and construction of the plant.[18]

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[18]Edward Berlin and Steven Agresta, "Prudence Investigation of Nuclear Construction Projects," a paper presented to the Twenty-Second Annual Iowa State Regulatory Conference on Public Utility Valuation and Rate Making Process (Ames, Iowa, May 18-20, 1983), pp. 7-14.

Three major state prudence investigations of cost overruns are described next. In addition, we report other state actions for dealing with cost overruns that rely on the concept of prudence to varying degrees.

Enrico Fermi-2

An excellent example of a construction cost overrun investigation by a state commission staff is the Staff Investigation of Enrico Fermi-2 Nuclear Power Project. The Michigan staff began its investigation by looking into the "ground rules" concerning the inclusion of a major utility investment in rate base in Michigan. Included in this was a cursory review of how the used-and-useful test and the prudence test have been applied in Michigan and other states. In Michigan, according to Bhatia and Fielek, the used-and-useful test is applied in a straightforward fashion: if a facility is in service, it is used and useful and includable in rate base; if not in service, it is not.[19] Because Michigan does not have construction certification authority for electric plants, the issue of need can first arise subsequent to the completion of the facility.

The Michigan Public Service Commission initiated an Enrico Fermi-2 prudence inquiry with two concerns. The first concern was the original decision to construct the plant; the second was the reasonableness of the expenditures during the construction of the plant.[20]

The Michigan staff therefore conducted a prudence investigation in three stages. The first stage dealt with the need for the project, including the need at the time of the initial decision, the continued need as established by periodic reviews, and the final need for the project, that is, whether the project represented excess capacity.

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[19]Hasso Bhatia and Michael A. Fielek, "A Plan for Investigation into the Prudency (sic) of Power Plant Expenditures," The Proceedings of the Fourth NARUC Biennial Regulatory Conference (Columbus: The National Regulatory Research Institute, 1984).

[20]Ibid.

In the second stage, staff conducted an investigation to establish a rough range of costs for the Enrico Fermi project, which could be considered reasonable compared with similar nuclear projects. This comparable cost study was conducted for the purpose of determining whether the presumption of prudence could be rebutted, in other words, whether there existed enough evidence for a prima facie case of management imprudence. If the results of this second stage showed that the construction costs of Enrico Fermi-2 fell close to or below the mean costs of comparable plants, then the prudence investigation would have stopped at this stage.

The third stage of the prudence investigation involved a detailed evaluation of the project management and decision-making process to determine which factors resulting in plant cost overruns were themselves the result of imprudent management and which were not. Throughout the third stage of the investigation, care was taken that all the decisions were evaluated in light of the circumstances, conditions, and information available at the time. If the decision resulted from a management evaluation reasonably based on cost-benefit analysis, risk analysis, technical feasibility, practicality, experience, and good judgment, then the decision was judged to be prudent. Even if the decision turned out to be wrong because of unforeseen future events, the decision was still deemed to be prudent. However, the staff recognized the fact that nuclear safety regulations were frequently changing, so that some degree of anticipatory judgment about this by utility management was required.[21]

The staff's Fermi-2 project investigatory team consisted of seven members. Also, a twelve-member Rate Base Advisory Committee was set up to define the scope of the investigation, to establish guidelines, evaluate criteria, to oversee the progress of the investigation, and to decide generic issues such as treatment of rework, effects of delay, regulatory impacts, and inflation adjustments.[22]

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[21] Ibid.

[22] Ibid.

The prudence investigation involved over 440 information requests and on-site personal interviews with key personnel including the senior utility management; the utility's project management team; contractors; vendors; suppliers; foremen from the site; and managers and auditors responsible for reporting, accounting, and financial control.

The Michigan Public Service Commission staff concentrated its investigation on only a handful of actions and decisions, based on their significance to the overall project. The actions and decisions that were examined for possible imprudence included (1) any action or decision causing significant project delays, (2) any major modifications in construction resulting from design or construction deficiency, (3) management deficiencies in project labor or control, (4) management deficiencies in quality assessment and quality control, (5) any action or decision subject to Nuclear Regulatory Commission citation, and (6) management deficiencies in vendor control.

The critical, but most difficult analysis was the determination of the cost of project delay due to imprudence. The investigators were aided by the state-of-the-art scheduling tools that the utility was utilizing. To determine if a decision caused project delay the prudence investigator had to determine whether the action was on the construction project's critical path, since only those items on the critical path add to the final project time. Even when a delay along the critical path was identified, the staff investigators were still left with the difficult task of deciding whether the delay was beyond the control of the utility and, if not, how much delay occurred. Once a delay was determined to have occurred as a result of imprudence, then the cost of the delay had to be determined and adjusted for inflation.

As a result of this retrospective prudence investigation, the Michigan Public Service Commission staff recommended that $365.48 million be disallowed from the estimated total project cost of $3.075 billion for Enrico Fermi-2. Of that total, approximately $122 million were disallowances due to project delays along the critical path, and the

remainder of the recommended disallowances represented an accumulation of many specific items of unnecessary cost incurrence resulting from poor supervision and management decisions.

This staff recommendation was made in testimony during a prudence inquiry conducted by the Michigan Public Service Commission. As of this writing, all the evidence has been presented to an administrative law judge who has not yet rendered a decision.[23]

Shoreham

Another significant retrospective prudence investigation was conducted by the State of New York Department of Public Service, initially with the assistance of a consulting firm and its subcontractor. The prudence investigation was ordered as Phase II of Commission Case 27563 to investigate the cost incurred by the Long Island Lighting Company (LILCO) in the construction of the Shoreham Nuclear Power Station.

An initial investigation determined that there were serious problems with LILCO's management of the Shoreham project. Based on the initial findings, the Department of Public Service dramatically increased the resources devoted to the investigation, and in February 1983 a second consulting firm was hired to assist the staff in conducting a "full-blown" retrospective investigation of LILCO's management of the Shoreham project. In conjunction with the consulting firm, the New York Department of Public Service formed a Shoreham Task Force consisting of eighteen full-time staff members, as well as fifteen part-time Task Force members who were called upon as necessary. The Task Force consisted of lawyers, engineers, accountants, and computer and clerical support staff.[24]

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[23]Personal communication with Dr. Hasso Bhatia, Michigan Public Service Commission Staff, January 23, 1985.

[24]See Executive Summary Testimony of Thomas G. Dvorsky, Shoreham Project Technical Coordinator, State of New York Department of Public Service (February 1984), Investigation of the Shoreham Nuclear Power Station, New York Public Service Commission Case 27563 - Phase II - Shoreham Prudence Investigation.

The Shoreham Task Force conducted its investigation by using on-site investigations at the LILCO home offices and at the Shoreham site. The Task Force reviewed files of 66 LILCO departments and offices and examined the files of 58 of LILCO's managers, including the President and Chairman of the LILCO Board. As a part of its investigation, the Task Force obtained approximately 10,000 documents relevant to the Shoreham construction. The Task Force also obtained LILCO's computerized accounting information system for Shoreham. The Task Force also obtained and reviewed copies of the project files of the architect/engineer, the construction manager, and the main piping and structural contractors. The Task Force then organized and placed all the documents and information received into a computerized record retrieval system, which ultimately contained over 1.5 million pages of information on microfilm. Finally, the Task Force interviewed 49 individuals including LILCO employees, contractors, and consultants involved in the Shoreham project.[25]

The Task Force reported finding serious mismanagement and inefficiencies throughout the project in each of the areas of project management, construction management, regulatory relations, engineering management, and quality control.[26] The factor identified by the Task Force to have caused the longest delay in the plant's completion was the procurement, fabrication, testing, and installation of the emergency diesel generators for the Shoreham plant. According to the Task Force, this failure resulted in delays that are estimated to have increased the cost of the Shoreham unit by $500 million.

Based on its findings, the State of New York Department of Public Service recommended that $1.55 billion of the cost of Shoreham should be excluded from rate base out of the then current total cost estimate of $3.85 billion. The staff's recommended adjustment was based on the assumption that the Shoreham unit would become operational in January 1985.

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[25]Ibid.

[26]Ibid.

The staff took the position that any additional costs that resulted from further delays should be borne by the stockholders. Thus, the New York Department of Public Service staff proposed that no more than $2.3 billion of the $3.85 billion construction expenditure in the Shoreham project should be allowed in rate base. The balance of the expenditure would be disallowed for being imprudently incurred.[27]

Since then, the management of LILCO has proposed a plan to phase the Shoreham investment into rate base over a 13-year period beginning July 1, 1984, 18 months before the plant's in-service date. The plan calls for LILCO stockholders to pay a $250 million "contribution to rate reduction" to settle the question of the prudence of the Shoreham investment. LILCO, nonetheless, maintains that all of its construction expenditure decisions in Shoreham were prudent.[28]

The New York Public Service Commission, instead, recently approved an agreement providing LILCO with emergency financing to pay $90 million for bonds maturing September 1, 1984. The agreement also gave the lending institution a third-mortgage of $1.2 billion as security for loans made by LILCO in the past. However, the Commission made it clear that its regulatory authority, pursuant to the provisions of the New York Public Service law, is not constrained by the agreement, leaving unconstrained the Commission's authority to make a prudence adjustment to the value of the Shoreham investment going into rate base.[29]

Zimmer

Another example of a state commission undertaking a retrospective prudence investigation is the investigation of the possible mismanagement

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[27] Ibid.

[28] "LILCO Outlines Plan to Recoup Shoreham Costs," The Wall Street Journal, 1 June 1984, p. 6.

[29] "New York PSC Approve LILCO Loan Agreement with Banks, Eliminates Any Limits on Future PSC Actions," NARUC Bulletin, No. 38-1984, September 17, 1984, p. 13.

and related costs involved in the construction of the M. H. Zimmer Nuclear Power Station. In this case, the investigation was conducted by a consultant under contract to the Public Utilities Commission of Ohio (PUCO). Zimmer construction was managed by the Cincinnati Gas and Electric Company on behalf of itself and two co-owners. The PUCO issued a request for a proposal on November 11, 1983 for a consulting firm to do three things: (1) develop a definition of mismanagement in a nuclear power project, (2) identify any mismanagement at the Zimmer project, and (3) quantify the cost of mismanagement associated with the Zimmer project. The PUCO hired a consulting firm, with a subconsultant, on December 20, 1983 to complete the study.[30]

The consultants performing the Zimmer prudence investigation relied on eleven books and ninety-nine articles to develop their definitions of management and mismanagement. Their view of management and mismanagement can be summed up as follows:

> ...[R]isk-taking [is] a normal part of management, and competent management must take risks. These risks, however, must be within an appropriate context, and not be a challenge to society or a danger to the public or the employees. However, a mistake made as a result of actions which were clearly predictable is, indeed, mismanagement. Further, failure to adjust or correct actions after a mistake has been identified is, also, mismanagement.[31]

The consultants then identified instances of possible mismanagement. Of these, two of the more important concern cost management: cost management after the 1981 NRC "immediate-action" letter and cost management for the Mark II pressure suppression containment. The NRC letter directed

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[30] O'Brien-Kreitzeng & Associates, M. H. Zimmer Nuclear Power Station: Analysis of Possible Mismanagement and Correlated Cost, prepared for the Public Utilities Commission of Ohio, June 15, 1984, p. 1-1.

[31] Ibid., p. 2-16.

that the utility take corrective measures for construction quality concerns. The NRC letter required, among other things, (1) an immediate increase in the size and technical expertise of the Cincinnati Gas and Electric Quality Assurance organization; (2) that action be taken by April 15, 1981 to assure the independence of the quality assurance/quality control function; (3) a complete reinspection of all quality control inspections; (4) a review and revision of all quality control inspection procedures by qualified design engineers and quality assurance personnel, and a temporary suspension of associated construction activities; and (5) training on new quality assurance/quality control (QA/QC) procedures and practices by all QA/QC personnel. The consultants also identified the high costs of the Mark II pressure suppression containment as possibly being the result of mismanagement. Two events in the early 1970s suggested that the design of the Mark II containment system was not adequate, and as a result the system was redesigned and suffered associated cost increases.

In order to quantify the incidence of mismanagement at the Zimmer project, the consultants grouped instances of possible mismanagement into three levels of significance. The first level, the policy level, represents the highest level of management responsibilities, including moral and ethical conduct, performance in good faith with the laws, competence, a dedication to quality and safety, and verification that the aforementioned policies are implemented. The second level, the control and performance level, reflects operations carried out by middle management within the broader policies of upper management. These areas of management include scheduling, quality, cost, and budget control; controlling craft productivity; documentation; planning and design control; personnel training; and developing organizational procedures. The third level of management relates to specific incidents, which are merely symptomatic representations of management policy and its implementation.

The first two levels, top management and middle management, were rated according to a point system. The consultants determined that mismanagement in a nuclear project could consist of a failure to manage any of the

following five functions: (1) responsible performance, (2) planning, (3) implementation, (4) maintenance of control, and (5) achievement of meaningful results. The consultants rated, on a subjective basis, each of these five functions of management as follows: a failure of management, 3; inadequate management, 2; adequate management, 1; and good management, 0. The following seven activities of middle management were rated: (1) planning; (2) project management and control; (3) scheduling; (4) engineering; (5) construction management; (6) procurement and contract management; and (7) quality assessment, quality control, and regulatory compliance. The overall rating for each of the seven activities was the average of the ratings for that activity in each of the five managerial functions. For example, the scheduling activity of middle management received the following functional ratings: responsible performance, 2; planning, 3; implementation, 2; maintenance of control, 2; and achievement of meaningful results, 2. An average scheduling rating of 2.2 resulted. According to the consultants a rating of 2.0 or more is indicative of mismanagment. The ratings by the consultants resulted in a finding of mismanagement (a score of 2.0 or more) for each of the seven activities at the middle management level.[32]

The consultants rated three activities of top management. They were (1) quality assurance/quality control, (2) cost management after the 1981 NRC immediate-action letter, and (3) cost management for the General Electric Mark II pressure suppression containment. The consultants rated top management decisions as inadequate or a failure in two of these categories, the exception being the utility's management of the Mark II containment costs, which the consultants rated as good.

In assessing the cost of mismanagement associated with the Zimmer project, the consultants found that, of the estimated $3.3 billion required to complete the facility as a nuclear unit, $1.7 billion would be the result of mismanagement. The consultants also concluded that if the utility

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[32]Ibid., pp. 2-18 to 2-22A.

were to cancel the plant the entire cost--$1.7 billion at that time--would be the result of mismanagement. Further, if the utility were to convert the nuclear plant to a coal-burning plant, $1.3 billion would be the result of mismanagement.

The consultants' report has been criticized by officials of the lead utility, the Cincinnati Gas and Electric Company, as being "simplistic," because it

> appears that the consultants could not quantify costs specifically related to mismanagement, as they were assigned to do by the commission. As a result...the consultants...concluded that everything they believed cannot be used in the conversion of the Zimmer plant to a coal-fired facility is attributable to mismanagement.[33]

The utility also disputed the consultants' conclusions that (1) $1.3 billion of the plant cannot be used in the coal conversion, (2) the utility should have suspended construction of Zimmer after the immediate-action letter from the NRC in April 1981, and (3) $326 million should be assessed against the utility because of the necessity to redesign the Mark II containment, when the report gave the company's own managerial and engineering effort a high rating.[34]

It should be remembered that the conclusions reached in the consultant's study do not necessarily reflect the views of the Commission or its staff, but the study is likely to be important evidence in a PUCO inquiry regarding the prudence of utility decisions about the Zimmer plant. Recently the Commission found reasonable cause to believe that there had

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[33]"Ohio Utility Criticizes Zimmer Study," Public Utilities Fortnightly, July 19, 1984, p. 52.

[34]Ibid. It should be noted that the utilities that are co-owners of the Zimmer plant have jointly filed suit against the General Electric Company and the Sargent & Lundy Engineers to recover damages associated with the nuclear steam supply system and the Mark II containment. See "Ohio, Zimmer Owners Seek Recovery of Damages," Public Utilities Fortnightly, August 16, 1984, p. 53.

been "imprudence or mismanagement"[35] in connection with the Zimmer plant. As a result of this finding, the Commission ordered an investigation in two phases. In the first phase of the investigation, the Commission will determine what portion of the Zimmer project that was specifically nuclear will never become used and useful as part of a coal plant. In the second phase of the investigation, the Commission will examine whether any imprudence or mismanagement occurred and whether any such imprudence or mismanagement caused the owners to convert the unit from nuclear to coal.

Final Outcome Test for Prudence
in Cost Overrun Cases

As mentioned, in our view the concept of prudence applies only to decisions, and the appropriate test for prudence is one of reasonableness under the circumstances. Because application of the concept is an emerging area of regulatory law, the prudent investment test is rarely, if ever, used in strict conformance with the guidelines set out at the beginning of this chapter. Indeed, only time and the courts will tell if these guidelines or some other guidelines evolve into established elements of a prudence inquiry. Concerning construction costs, several states have judged the reasonableness of the final costs resulting from management decisions rather than the decisions themselves. Sometimes this "final outcome" test of whether ratepayers should bear the cost has been linked to the concept of prudence. Other times it has not: investment costs may be excluded from rate base on the basis of "usefulness," for example.

The Enrico Fermi-2, Shoreham, and Zimmer investigations just discussed are among the state applications that best conform to our guidelines, but even in these investigations some features of a final outcome test may appear together with the test of reasonableness under the circumstances. Certainly, it would be hard to prove that a decision that led to a good

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[35]"Ohio: Commission Initiates Zimmer Prudence Investigation," Public Utilities Fortnightly, December 6, 1984, p. 59.

final outcome was unreasonable under the circumstances (even though it is easy to imagine such a case). Consequently, investigators are likely to consider the final outcome of a decision along with the quality of the decision making. For example, in the Zimmer investigation the consultants found that the management associated with the Zimmer plant was, by and large, inadequate. This finding was based in part on "achievement of meaningful results."

Further, when is expert testimony about reasonableness objective or subjective, and to what degree does it always implicitly, if not explicitly, rely on knowing the final outcome? The use of expert opinion, presumably based on factual evidence, cannot be avoided in a retrospective prudence inquiry. In the Zimmer investigation, it is unclear whether the consultants used an objective or subjective rating to derive their findings. Hence, it is not always clear from their documentation whether the consultants' rating of the utility's failure or success in managing the project could be used with the prudence test under the guidelines set out above. It is questionable whether a consultants' average numerical rating of several activities, including achievement of results, applies the test of reasonableness under the circumstances to utility decisions. Further, choice of a particular average rating as a borderline between good and bad management may appear too subjective. While any opinion, including an expert opinion, is inherently subjective, that opinion must be sure to focus on the quality, not the outcome, of the decisions made.

In one state, the use of a final outcome test for judging the prudence or imprudence of construction cost overruns is the method set out in recent legislation. The Kansas legislature enacted a law that specifically empowers the Kansas State Corporation Commission to exclude from rate base construction costs that are a result of imprudence or inefficiency. The statute enumerates several tests to judge imprudence, including (1) a comparison of the final cost of the plant to the final costs of other comparable facilities, (2) a comparison of the cost overruns at the plant

to the cost overruns at other comparable facilities, (3) a comparison of the rates resulting from the new plant as opposed to prior rates, and (4) an assessment of the impact of the new rates on the state's economy. The statute also provides that the burden of proving costs to be prudent is automatically shifted to the utility if the construction cost overruns are more than 200 percent of the utility's original cost estimate.[36] It is interesting that many of the tests set forth in the Kansas statute are similar to the comparable cost method used by the Michigan Public Service Commission staff in its investigation to overcome the presumption of prudence. The Kansas statute, however, appears to allow a comparable cost test to be used actually to find those costs that are imprudent.

Some state commissions have developed a final outcome test that either implements or supplements the prudent investment test for the purpose of controlling the inclusion of excessive construction costs in rates. One example is the test applied by the Connecticut Public Utilities Control Authority (PUCA) at the behest of the state legislature. It sets a "cap," or a maximum final cost for which Connecticut ratepayers could be charged, for the Seabrook-1 nuclear unit.[37] Legislation provides that the cap could be exceeded to account for (1) an increase in the costs of labor and materials to the extent that such increase is due to an inflation rate above 10 percent per year, (2) an increase in financing costs related to an increase in the weighted average rate for allowance for funds used during construction above 10.25 percent per year, (3) any costs directly attributable to new regulations adopted by the Nuclear Regulatory Commission, and (4) any costs due to unforeseen and unavoidable labor

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[36] See KAN. STAT. ANNO. 66-128 (1984).

[37] "UI Proposal Would Restrict Return on Seabrook-1 Costs Topping $4.5 Billion," Electric Utility Week, September 24, 1984, pp. 6-7; and "UI Explains Proposal to Limit Return on Seabrook-1 Costs Topping $4.5 Billion," Electric Utility Week, October 1, 1984, p. 4.

stoppages.[38] The PUCA set the cap at $4.7 billion in direct construction costs.[39]

One year earlier, the Connecticut legislature had set a $3.54 billion cap on the recoverable investment in the Millstone-3 nuclear unit.[40] The PUCA, however, recently selected a consulting firm to conduct a retrospective prudence audit of the Millstone-3 nuclear plant. Thus, while it is not yet clear whether the cap is meant to supplement or supplant the prudent investment test in the Seabrook-1 case, it is clear that the PUCA views the construction cap as a supplement to the prudent investment test in the Millstone-3 case.[41]

The New York Public Service Commission set a cap on the Nine-Mile Point-2 nuclear plant. In this case, the Commission has made it quite clear that the cap and the rate-of-return incentive supplement (rather than supplant) the prudent investment test. The Commission indicated that any portion of the cost of the plant that is attributable to mismanagement will not be recoverable by the utility. The Commission has also indicated that it intends to have the staff conduct a comprehensive, retrospective prudence investigation of the Nine-Mile Point nuclear plant, similar in most respects to the Shoreham prudence investigation.[42]

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[38]"Conn. Legislature Triggers CWIP Law, Directs Limits on Seabrook-1 Cost," Electric Utility Week, May 7, 1984, pp. 1-2.

[39]See Re Construction Costs of Seabrook Unit No. 1, Docket No. 84-06-17, (Conn. DPUC, Sept. 27, 1984).

[40]Connecticut Public Act No. 83-99.

[41]See "Connecticut Commission Endorses Seabrook Unit Completion," Public Utilities Fortnightly, January 10, 1985, p. 52 and "Connecticut DPUC to Have Prudency Audit Conducted on Millstone Nuclear Plant," NARUC Bulletin, No. 50-1984, December 10, 1984, p. 24.

[42]"Gioia of New York Comments on New Niagara Mohawk Estimate of $5.1 Billion Cost of 9-Mile 2 Plant," NARUC Bulletin, No. 16-1984, April 16, 1984, p. 20.

The New York Public Service Commission's cap for the Nine-Mile Point-2 nuclear plant operates in conjunction with an incentive rate of return, imposed in 1982. The incentive rate of return requires that stockholders of the owner-utilities share 20 percent of all costs of Nine-Mile Point-2 in excess of $4.6 billion. Under the cap imposed by the Commission, the cost sharing ceases at $5.4 billion, and 100 percent of any additional costs is to be borne by the utility stockholders. The New York Commission held that the cap is neither unfair nor unlawful, because it is based on the utilities' own current cost estimate, which the Commission held to be reasonable, and includes an allowance for a 6-month delay in the currently estimated October 1986 operation date. The Commission explicitly recognized that, with a cap, the owner-utilities could bear a penalty for some potential cost overruns that are not within the control of the management (and hence could not be said to be imprudent). The Commission stated that, given (1) the advanced stage of the project, (2) the reasonableness of the cap figure, and (3) the public interest in having certainty about the maximum cost of the project, the imposition of such a risk on the utilities is reasonable. Nevertheless, the Commission would consider a petition from any party to increase or decrease the cap as a result of extraordinary events beyond the control of the utilities.[43]

New Jersey has also adopted a similar cap in its proceedings.[44] But, the reliance on the concept of prudence is unclear.

Final outcome tests for disallowance of utility investments may be justified on some basis other than prudence. Commissions have placed a cap

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[43]"New York PSC Agrees to Set Cap of $5.4 Billion on Costs Owners of 9-Mile Point 2 Can Pass to Customers," NARUC Bulletin, No. 28-1984, pp. 5-6.

[44]Gerald Charnoff, "Why Management Did It All Right: Overregulation and Other Acts of God," a paper presented to the Seventh Annual National Conference of Regulatory Attorneys (Madison, June 4, 1984).

on project costs without any reference to the prudence test. For instance, the California Public Utilities Commission has approved an 80-mile 500-kV line for the Southern California Edison Company, subject to a cap on its cost. Construction costs above the cap will not be recovered from ratepayers. The cap will be based on a cost estimate to be filed by the utility with the Commission, subject, of course, to Commission approval. The Commission will approve future adjustments in the cap only if the utility can show that (1) changes are needed, (2) the changes are cost effective, and (3) the changes are required by circumstances that were unforeseen at the time of the original estimate.[45]

Plant Abandonments

The most frequent application of the prudent investment test in recent years has been in the situation where a utility plant has been abandoned or cancelled. In this situation, commissions must decide whether to allow the utility to recover all, part, or none of its investment in cancelled plant. Unlike the cost overruns inquiries, these inquiries are usually not preceded by very extensive staff investigations.

Many cases involving abandoned or cancelled electric plants have been decided by state and federal commissions. Examples of recent commission actions in such cases appear in table 3-1. These examples, while not a comprehensive list, show the wide variety of regulatory treatments for abandoned or cancelled plant costs by state and federal commissions. The table contains information about thirty-one state commissions, the District of Columbia Commission, and the Federal Energy Regulatory Commission. It shows whether each commission typically allows any recovery of the costs of abandoned or cancelled electric plants and the number of years over which utilities have been allowed to amortize these costs. Also shown are whether rate base treatment of the unamortized balance is permitted and

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45"PUC Okays 80-Mile-Long, 500-kV Line for Southern California Edison," Electric Utility Week, October 15, 1984, p. 11.

TABLE 3-1

EXAMPLES OF FEDERAL AND STATE COMMISSION ACTIONS
IN RECENT ABANDONED OR CANCELLED ELECTRIC PLANT CASES

State Agency by State	Whether Any Cost Recovery Is Allowed	Amortization Period in years	Treatment of Unamortized Balance	Treatment of AFUDC
Arizona	No	-----	-----	-----
California	Yes	4,5	No Return	Amortized, Disallowed
Connecticut	Yes	10	Return Allowed, No Return	Amortized
District of Columbia	Yes	10	Return Allowed	Amortized
FERC	Yes	5,10	No Return	Amortized
Idaho	No	-----	-----	-----
Indiana	Yes	15	No Return	Amortized
Iowa	Yes	5	Return Allowed	-----
Maine	Yes	-----	No Return	-----
Maryland	Yes	7,10	No Return	Amortized
Massachusetts	Yes	2,3,13	No Return, Levelized Carrying Charge on Non-AFUDC	Amortized only for Debt and Preferred Equity
Michigan	Yes	3,10	No Return	Amortized
Missouri	No	-----	-----	-----
Minnesota	Yes	-----	No Return	-----
Montana	No	-----	-----	-----
Nevada	Yes	-----	No Return	-----
New Hampshire	No	-----	-----	-----
New Jersey	Yes	15,20	No Return	Amortized
New York	Yes	3,5,10,15	Return Allowed	Amortized
North Carolina	Yes	5,10	No Return	Amortized
North Dakota	Yes	-----	No Return	-----
Ohio	No	-----	-----	-----
Oklahoma	Yes	10	Return on Debt and Preferred Equity	Amortized
Oregon	Yes	-----	No Return	Amortized, No Amortization
Pennsylvania	Yes	10	No Return	Amortized
South Dakota	Yes	5,--	No Return	Amortized
Texas	Yes	10	No Return	Amortized
Vermont	Yes	10	No Return	Amortized
Virginia	Yes	10,15	No Return	Amortized

TABLE 3-1--Continued

State Agency by State	Whether Any Cost Recovery Is Allowed	Amortization Period in years	Treatment of Unamortized Balance	Treatment of AFUDC
Washington	Yes	10	No Return	Amortized, No Amortization
West Virginia	Yes	10,20	No Return	Amortized
Wisconsin	Yes	5	No Return, Return Allowed	Amortized
Wyoming	No	-----	-----	-----

Sources: "DOE Sees Investors Shielded from 70% of Nuclear Unit Cancellation Costs," Electric Utility Week, May 30, 1983, pp. 8-9; Shippen Howe, "A Survey of Regulatory Treatment of Plant Cancellation Costs," Public Utilities Fortnightly, March 31, 1983, pp. 52-58; David Wagman, "NRRI Report: Many Commissions Deny Recovery Through Ratepayers of Investment in Cancelled Nuclear Plants," NRRI Quarterly Bulletin: No. 17, ed. Vivian Witkind Davis (Columbus: NRRI, 1984), at pp. 9-17; and updates from Electric Utility Week and Public Utilities Fortnightly.

whether allowance for funds used during construction (AFUDC) is includable in the cost to be recovered. The entries represent the results of one or more cases in each state listed. Hence, multiple entries can appear for a state, one for each case. Dashed lines indicate cases where the information is not applicable or not available. Actions for any one state tend to be uniform with respect to cost recovery, return on unamortized balance, and AFUDC, but vary considerably for the amortization period.

In most cases, the presumption of prudence operates to allow the recovery of costs sunk into an abandoned or cancelled plant. In general, state commissions have allowed recovery of the prudently incurred costs of an abandoned or cancelled plant, but have often divided the costs between the investor and the ratepayer by means of the treatment of amortization.

Many of the state commissions do not allow the unamortized balance of the investment in rate base, and some do not allow any cost recovery of the allowance for funds used during construction.

Most state commissions have permitted at least partial recovery of the costs of an abandoned or cancelled utility plant. For example, the Virginia State Corporation Commission found that the timing of a decision by the Virginia Electric and Power Company to cancel its North Anna-3 unit was not imprudent and that a recovery of some of the construction and cancellation costs should be allowed. While the utility had requested that it be allowed to amortize its investment of $481.7 million, the Commission only allowed a recovery of $258 million in costs. The company had also requested that a 10-year amortization period be used and that the company be allowed to earn a debt and equity return on the unamortized balance. The Commission was unable to find that the utility's actions were imprudent so as to disallow cost recovery for the cancelled plant. The Commission found, however, based on its own independent investigation, that the 1980 North Anna feasibility study was sufficiently flawed so that the Commission decided to increase the amortization period to shift more of the total cancellation costs onto the stockholders. Instead of the 10-year amortization period that the utility requested, the Commission imposed a 15-year amortization period and denied any return on the unamortized balance. The 15-year period almost equally divided the cancellation costs between ratepayers and stockholders.[46] Thus, although no imprudence was explicitly found, the shareholders were required to bear at least part of the cancellation costs of North Anna-3.

The New Jersey Board of Public Utilities (NJBPU) has also recently allowed recovery of a cancelled plant based on its finding that the expenditures in the plant were prudently incurred. In 1982 the NJBPU

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[46]See Virginia State Corp. Commission v. Virginia Electric & Power Co., Case No. PUE830041 (March 27, 1984); see also, "Recovery of Nuclear Plant Cancellation Costs Allowed," Public Utilities Fortnightly, May 24, 1984, pp. 58-59, and Electric Utility Week, April 18, 1983.

approved the recovery of $12.5 million for the abandonment costs associated with the Sterling nuclear plant, amortized over a 20-year period, in keeping with the NJBPU's policy that the prudently incurred investments in an abandoned plant should be recoverable. In a recent case, the NJBPU refused to shorten the amortization period, but did add $1.5 million to the amount recoverable to reflect the additional abandonment costs incurred since its initial decision in 1982.[47]

The NJBPU also found that the decisions to start and then to abandon the construction of the Hope Creek-2 nuclear unit were prudently made. The NJBPU allowed the abandonment costs to be recovered over a 15-year period, with no return allowed on the unamortized balance. The investors, in being denied further returns on the unamortized balance of their investment after the plant was abandoned, are thus required to share the loss with ratepayers.[48]

However, in other cases, state commissions disallowed the recovery of part or all of the costs of an abandoned or cancelled plant because of imprudence in the timing of the decision. For example, in a Commonwealth Electric Company case,[49] the Massachusetts Department of Public Utilities denied recovery of costs of a plant because it judged that the plant should have been abandoned sooner; it held that costs beyond the time that the plant should have been abandoned were imprudently incurred. In another similar case, the Texas Public Utility Commission disallowed $195 million

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[47]"New Jersey BPU Authorizes Rockland Electric Rate Increase," NARUC Bulletin, No. 32-1984, August 6, 1984, pp. 11-12.

[48]"New Jersey BPU Finds Hope Creek 2 Nuclear Plant Abandonment Prudently Made," NARUC Bulletin, No. 12-1982, March 22, 1982, pp. 13-14. Also see, in the Matter of Utility Construction Plans, Docket No. 8012-914 (NJBPU, April 1, 1982).

[49]In re Commonwealth Electric Co., 47 PUR4th 229 (1982).

of the $361 million invested in an abandoned plant on the basis that the utility was imprudent in not abandoning the plant sooner.[50]

In another case that relied on the concept of prudence, the New York Public Service Commission (NYSPC) denied full recovery to the Long Island Lighting Company and the New York State Electric and Gas Corporation of costs related to the planning and attempted licensing of the New Haven nuclear power facility. Instead, the NYPSC disallowed 30 percent of the costs incurred by the utilities on the grounds that the companies were imprudent in pressing for licensing of the plant in 1978, when a declining growth rate should have led them to conclude that the plant would not be needed.[51]

In a case decided in 1984, the Idaho Public Utilities Commission refused to allow the Idaho Power Company to charge ratepayers for $11.9 million of the $14.1 million that it had spent in the 1970s on the cancelled Pioneer coal-fired plant. In 1976, the Idaho Public Utilities Commission had turned down the siting application for the plant, but the company had previously entered into contracts requiring subsequent expenditures.[52] The Commission did not allow recovery of any expenditures incurred after January 13, 1975, the date of the first public hearing on the plant. From that time on, according to the Commission, the company was on notice that there was opposition to its siting application, and the only reasonable further expenditures were those associated with processing the application, not those associated with the construction of the plant.

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[50]In re Houston Lighting & Power Co., 50 PUR4th 157 (1982).

[51]Re Long Island Lighting Co. and New York State Electric and Gas Corp., Case 27811, Opinion No. 84-25 (NYPSC, 1984); and "Commission Limits Recovery for Suspended Nuclear Project," Public Utilities Fortnightly, December 6, 1984, pp. 64-65.

[52]See "Idaho PUC Limits Cost Recovery for Abandoned Generator," NARUC Bulletin, No. 32-1984, August 6, 1984, pp. 18-19.

Prudence issues have also arisen in federal cases associated with whether construction work in progress (CWIP) can be included in rates for a cancelled plant or for a plant on which construction has been suspended. This issue has arisen under the Federal Energy Regulatory Commission's current CWIP rule, which permits an electric utility to include 50 percent of its prudently incurred construction costs in rate base, subject to a limitation that the CWIP increase cannot exceed 6 percent of the utility's wholesale revenues. For example, an FERC administrative law judge held that it is "unreasonable" to include construction work in progress in rate base when construction on a plant (Seabrook-1) has been formally suspended and there is no assurance that the plant would ever be completed.[53]

In another FERC case, an administrative law judge held that the New England Power Company cannot charge its ratepayers for costs associated with the abandoned Pilgrim II nuclear power plant incurred before July 1980 because the New England Power Company had been imprudent in investing in the plant. According to the administrative law judge, the New England Power Company had been imprudent because it had accepted the terms of the Pilgrim-II Joint Ownership Agreement, which constrained the New England Power Company, a minority participant in the project, from exercising any control over the actions of the lead utility, the Boston Edison Company. The New England Power Company had also given up its right to sue the Boston Edison Company for losses caused by the mistakes, mismanagement, or misconduct of Boston Edison.[54]

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[53]New England Power Co., Docket No. ER83-674-005 (FERC ALJ, June 20, 1984). The joint owners of the Seabrook nuclear project have since voted to restart the construction of the Seabrook-1 unit, under a newly-formed division of the Public Service Company of New Hampshire called New Hampshire Yankee. The joint owners planned to have New Hampshire Yankee become a separate, independent company, presumably under the jurisdiction of the Federal Energy Regulatory Commission. See "New Hampshire: Seabrook Construction to Resume," Public Utilities Fortnightly, August 2, 1984, pp. 47-48.

[54]See Re New England Power Co., FERC Docket No. ER82-703-000, (FERC ALJ., May 4, 1984); also see "Cancelled Plant Costs Denied under Joint Participation Agreement," Public Utilities Fortnightly, June 21, 1984, pp. 66-67.

In other cases, where utilities have relied on the prudence test for inclusion of abandoned plant costs, courts or commissions have applied the "used and useful" test to prevent ratepayers from bearing any of the costs associated with such plant. A leading case in this regarding is the case of Consumer's Counsel v. Public Utilities Commission.[55] This case was discussed in detail in an earlier National Regulatory Research Institute report,[56] but the highlights of the case are mentioned here. In the case, the Ohio Supreme Court held that the Ohio Commission had exceeded its statutory authority when it approved amortization of an investment in four terminated nuclear plants on the basis of utility prudence. As stated in the Institute report:

> While the case was actually determined on the issue of whether the cancelled plant expenditures represent "the cost to the utility of rendering the public utility service for the test period" as required in Ohio's statutory language, the court set the test period considerations aside in its reasoning and disallowed the amortization on the grounds that the investment never provided anyservice whatsoever to the utility's customers. Thus, the disallowance of the utility investment as an expenditure that could be amortized was based on a theory somewhat akin to the "used and useful" doctrine, which concerns the inclusion of plant in rate base....And while the Ohio Supreme Court based its decision on an Ohio statute, other states have similar statues requiring plants to be "used and useful" in order to be included in the rate base.[57]

Several other states have used a similar rationale. For instance, the Montana Public Service Commission denied the Pacific Power and Light Company any relief associated with the company's investment in the Pebble Springs and the WPPSS-5 nuclear power projects. The company claimed recovery on the basis of prudence. The Commission, in denying recovery,

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[55]Consumers' Counsel v. Pub. Util. Comm., 67 Ohio St. 2d 153 (1981).

[56]Russel J. Profozich et al., Commission Preapproval of Utility Investments (Columbus: NRRI, 1981).

[57]Ibid., pp. 28-29.

determined that the appropriate test for recovery was not the prudent investment test, but was rather whether the projects were actually used and useful for the convenience of the public. In reaching its conclusion that no recovery would be allowed because the plant was not used and useful, the Commission reasoned that the utility shareholders risk not only the possibility that they may not earn a return on their investment, but they risk their initial investment itself if the project does not become used and useful. To hold otherwise would allow a utility's shareholder to have an investment that was risk-free or subject to only a limited risk.[58]

The Missouri Public Service Commission based its denial of recovery for the cost of the cancelled Callaway-2 nuclear unit on the language contained in the "Proposition One" initiative that was approved by voters in 1976 to ban construction work in progress. The operative language in Proposition One is that any "cost associated with owning...or financing any property before it becomes fully operational and used for service is unjust and unreasonable and is prohibited." The Missouri Public Service Commission interpreted this language as prohibiting any recovery of cancelled plant, whether prudently decided or not, if the plant is not used for service.[59]

One state, which has in the past applied the prudent investment test in an attempt to balance investor and ratepayer interests when a plant is cancelled or abandoned, has recently announced a change of policy. The Massachusetts Department of Public Utilities (DPU) has stated that the used-and-useful test will be used instead of the prudence test, at least for certain applications. If an electric plant on which construction is

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[58]See "Montana PSC Denied Pacific P&L Rate Relief for Two Abandoned Nuclear Projects," NARUC Bulletin, No. 19-1983, May 9, 1983, pp. 10-11; see also Pacific Power & Light, 53 PUR4th 24 (Mont. PSC, 1983).

[59]See In re Union Electric Company, Case No. ER83-163 (Mo. PSC, 1984); see also "PSC Denies U.E. Cancelled-Plant Recovery; Missouri 'Proposition One' Strikes Again," Electric Utility Week, October 31, 1984, pp. 1-2.

begun after July 31, 1984 is cancelled or abandoned, the utility will bear the entire risk of loss.[60]

Capacity Additions

For the most part, state commissions have been reluctant to use the prudence test to overrule capacity addition decisons. For example, the Michigan Public Service Commission held in a recent case that the decision by Detroit Edison to initiate the Greenwood-2 and -3 nuclear project was reasonable and prudent:

> The decision of applicant's [Detroit Edison's] board of directors to initiate the project was based on a load forecast issued in April, 1971. This forecast projected a summer peak demand of 11,650 megawatts in 1980. In mid-1971, applicant's installed generating capacity was 6,844 megawatts. The load forecast was based on an assumed continuation of historical load growth of 7.1 percent compounded annually.[61]

The initial projected growth rates were not realized. However, the Commission refused to substitute its judgment for that of the utility's planning department, which continued to find that the Greenwood project was needed until the units were abandoned in 1981. The Commission held that the utility's decision in 1978 to resume construction of the Greenwood project, after several years of suspension due to financing problems, was prudent given the facts as they existed at the time.[62]

Also, the Public Utilities Commission of Ohio, in determining whether the Dayton Power & Light Company had excess capacity, recently found that "[t]here had been no showing that applicant's [Dayton Power & Light's]

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[60]See In Re Western Massachusetts Electric Co. MassDPU Order 84-25 (Mass. DPU, 1984); See also "Mass. Bars Abandonment Cost Recovery for Plants Begun After July 31, 1984," Electric Utility Week, August 6, 1984, pp. 1-2.

[61]Re Detroit Edison Company, 52 PUR4th 318, 324 (Mich. PSC, 1983).

[62]Id., p. 325-328.

capacity planning has, in any way, been imprudent."[63] This indicates again that state commissions are reluctant to find that decisions based on a utility's demand forecast and capacity planning process are imprudent.

Many commissions hold that as long as "state-of-the-art" demand forecasting methods are used there should be no finding of imprudence. In short, the mere existence of excess capacity is not necessarily indicative of an imprudent demand forecasting or capacity planning process (the decision-making process), which is the subject of a prudence investigation. As the Iowa State Commerce Commission put it:

> extremely sophisticated forecasting methods are of recent origin and were not generally available for use during the time company's planning decisions were being made [for plants now being brought into service].[64]

But several state commissions also held that the question of prudence applies not only to the initial investment decision but also to decisions made (or not made) during construction about the continuing need for additional power. In this view, use of the prudence test requires an examination of management's ongoing decision-making process. As stated by the Iowa State Commerce Commission:

> The prudency of the management decision to invest in plant at the time the decision was made is a factor in the balancing process, but does not immunize company from penalties for excess capacity....The prudency test is a factor in balancing because public policy requires a reasonable amount of leeway in the management decision-making process; their decisions should be respected by us so long as the end result of those decisions is consistent with public policy. However, management of [a] company is under a continuing duty to reevaluate the prudency of its decisions and to readjust its actions accordingly, and thus, the prudency of the decision at the time the decision was made cannot end our inquiry.[65]

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[63]Re Dayton Power and Light Co., 45 PUR4th 549 (1982).

[64]Re Iowa Power & Light Co., 51 PUR4th 405, 411 (1983).

[65]Id., p. 412. Also see Re Iowa Public Service Co., 46 PUR4th 339, 368 (Iowa CC, 1982).

This responsibility to reevaluate initial decisions in light of changed circumstances is, of course, related to the responsibilities set out in the previous discussion of plant abandonments and cancellations. A failure to cancel a project that was prudently initiated, after it is no longer prudent to continue the project, can result in a finding of imprudence.[66]

Many commissions have dealt with excess capacity questions in cases where utilities have defended the resulting capacity on the basis that it resulted from prudent decision making.[67] However, at least two commissions have found a utility's capacity planning process to be imprudent. In one instance, the Florida Supreme Court upheld the Florida Public Service Commission's decision to exclude the Gulf Power Company's 50 percent interest in a coal-fired unit from rate base because of imprudent management decisions related to faulty load forecasting that failed to recognize that excess capacity would result from the capacity addition.[68]

In another case, the California Public Utilities Commission assessed a $14.4 million penalty against the Pacific Gas and Electric Company for its failure to pursue rigorously cogeneration as an energy source. The finding was based, in part, on a computer model for resource planning analysis introduced by an intervenor, the Environmental Defense Fund. The company's resource planning process was judged against the EDF resource planning analysis and was found to be inadequate in its treatment of cogeneration as

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[66]See Re Rochester Gas & Electric Corp., 41 PUR4th 438 (N.Y.P.S.C., 1981); Boston Edison Co., PUR4th 431 (Mass. DPU, 1982): Re Iowa Public Service Co., 46 PUR4th 339 (Iowa CC, 1982); and Re Wisconsin Electric Power Co., [Current State Decision] Util. L. Rep. Para. 23,557 (Wis. PSC, 1981).

[67]Alvin Kaufman, Kevin Kelly, and Ross Hemphill, Commission Treatment of Overcapacity in the Electric Power Industry (Columbus: The National Regulatory Research Institute, 1984).

[68]See Gulf Power Co. v. Florida Pub. Service Commission, 453 So.2d 799 (Fla., 1984); and "Court Upholds Rate Base Adjustment for Excess Capacity," Public Utilities Fortnightly, November 22, 1984, p. 69.

an energy source.[69] The case may serve as a warning that, as the state-of-the-art of demand forecasting tools and capacity planning models improves, utilities will be expected to keep pace with these developments in order to be adjudged prudent in their planning decisions.

Natural Gas Applications

Few state commission applications of the prudence test to the natural gas industry were found. However, states have a keen interest in the federal level findings of prudence (reported in chapter 2) regarding the gas purchase practices of interstate pipelines. In particular, many states question the prudence of various producer-pipeline contracts containing take-or-pay, third-party most-favored nation, and oil parity clauses, and lacking market-out clauses.

One example of a gas-related prudence inquiry is the actions of the Attorney General of Alaska before the Federal Energy Regulatory Commission and the Alaska Public Utilities Commission alleging that $1.6 billion of the $8 billion expenditures associated with the Trans Alaska Pipeline System were the result of managerial imprudence. The case involves an assessment of historical facts, which has utilized 600,000 records and has required a computerized document retrieval system. A computer model calculated the portion of costs attributable to the underutilization of construction equipment.[70]

Another example concerns a synthetic natural gas (SNG) plant being mothballed, that is, at least temporarily abandoned. It is the Marysville plant owned by the Consumers Power Company in Michigan. In the mid-1970s, the Marysville plant was an operating plant producing SNG from imported liquefied petroleum gas feedstocks. However, gas from other, less expensive

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[69]"California PUC to Compensate Environmental Defense Fund for Participation in PG&E Case," NARUC Bulletin, No. 38-1984, September 17, 1984, p. 10.

[70]Speck, "Proving Imprudent Management," pp. 6-7.

sources became available as natural gas supplies increased under the NGPA. As a result, Consumers Power Company announced that it intended to mothball the Marysville SNG plant for an indefinite period beginning in late 1979.

The Michigan Public Service Commission, in a subsequent case, excluded the Marysville SNG plant from rate base because the plant was incapable of responding to a short term gas supply disruption and was therefore not used and useful. However, the plant was being preserved in a mothballed state as insurance for ratepayers against future long term supply shortages. The Commission decided that this was a prudent utility decision and allowed the utility to recover the surveillance, upkeep, and mothballing costs of the plant. The Commission thus used a variety of regulatory tools--the used-and-useful test, the prudence test, and "a balancing of interests test"--to reach its decision.[71]

The concept of prudence was applied in an "informal" plant abandonment associated with a liquefied natural gas facility--the plant construction suspension of the Point Conception liquefied natural gas (LNG) terminal in California. This project was undertaken as a part of a plan by the Southern California Gas Company and the Pacific Gas and Electric Company to ship LNG from Indonesia and Southern Alaska to California. However, because of the increased availability of natural gas supplies (and the resulting decreased demand for more costly gas, such as LNG), the companies suspended construction of the plant. They then filed applications for a partial recovery of construction costs, including a return on allowance for funds used during construction, while also seeking authority to be allowed to resume construction at some later date when the demand for more costly gas might be greater.

The California Public Utilities Commission found that the management decisions to initiate the project and later to suspend construction were prudent when made and, therefore, gave the utilities two options. The

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[71]Re Consumers Power Company, 52 PUR4th 536 (Mich. PSC, 1983).

first option was that the companies might decide formally to abandon the plant, in which case the utilities would recover the direct project expenditures without AFUDC. The second option was that the companies might take up to 3 years to reevaluate the feasibility of the project, during which time the project site might be included in rate base as plant held for future use, with the direct costs of the plant to be partially recovered over a 4-year amortization period. The Commission made it clear that it would not allow recovery of AFUDC unless the plant comes into service and, hence, becomes used and useful.[72]

Summary and Discussion

The examples in this chapter illustrate that the use of the prudent investment test is indeed an emerging area of regulatory law. In conducting a prudence inquiry, a state commission may wish to assure that certain guidelines are followed. Initially, the burden of proof rests with the commission, staff, or other interested party to show that the utility's decision should not be presumed to be prudent. Once the presumption of prudence is rebutted, a commission is then prepared to examine the prudence of that decision. The decision should be judged on the basis of an objective test of reasonableness under the circumstances. Further, the commission's judgment must not rely on hindsight for determining whether the utility made a reasonable decision. Then, a factual inquiry into the circumstances in effect at the time of that decision is required. The final outcome of the decision ought not to matter. However, decisions made by the utility along the way, after the initial decision to make the investment, are properly part of a prudence inquiry. As a result, the commission needs to be specific about which decision (or decisions) is the subject of the investigation and about when the decision was made.

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[72]See Re Southern California Gas Co., Decision No. 84-09-089, Application Nos. 82-12-02 et seq. (Calif. PUC, Sept. 6, 1984), and "Temporary Rate Base Treatment Buys Time for Feasibility Review," Public Utilities Fortnightly, November 8, 1984, p. 66.

The use of the prudence concept is not a simple solution to a complex issue; instead, the determination of prudence may be quite complex. Commissions often rely on an extensive staff investigation to develop the evidence needed to judge prudence. It should be recognized that substantial resources might be necessary to conduct such an investigation. The use of consultants may be required, particularly if the investigation involves a nuclear power plant.

Several state commissions have conducted staff investigations to assess what portion, if any, of construction cost overruns for a plant about to come into service is the result of imprudence. These studies have been lengthy and expensive. They require an examinination in detail of the facts and circumstances known at the time a decision was taken. From these, the state commission obtains the information that allows a judgment about how much of the investment in plant ought to be allowed in rate base.

In varying degrees, commissions are relying on the test of reasonableness under the circumstances to adjudge prudence. Some use the test explicitly. Others may use this test together with some consideration of the final outcome of management decisions. Thus, it is difficult in practice to determine how closely commissions follow our "proscription against hindsight" guideline--especially in the construction cost overruns cases where the objective is not simply to judge prudence but also to determine the cost consequences, that is, the final outcome, of poor decisions.

In construction cost overruns inquiries, use of the prudent investment test may be said to work against utility interests in that the used-and-useful standard alone, depending on how it is interpreted, might lead to full cost recovery for an operating generating station. The opposite is usually the case where the prudence test is applied to abandoned plant. Here, utilities often introduce the prudent investment test in defense of their decisions.

The prudent investment test has recently been used most frequently by utilities to recover a portion of the costs of their cancelled or abandoned plants. In most cases where the prudent investment test has been utilized, the presumption of prudence has been applied to allow a utility to recover most of its investment. When recovery has been allowed, many state commissions have allowed the amortization of the costs over a period of years and have denied the utilities rate base treatment of the unamortized cost. This treatment of cancellation costs, in effect, divides the costs of an abandoned or cancelled plant between the ratepayers and utility investors. However, the prudence test does not always work in utility favor in these cases. Some commissions have denied recovery of the costs of an abandoned or cancelled plant based on a finding of imprudence. Frequently in such cases, commissions cite both prudence and used and useful as concepts that contribute to their findings.

The alternative to plant abandonment, of course, is to continue construction of the plant to completion. The prudent investment test has not been used very often for finding imprudence in electric utility decisions involving capacity additions. Presumably, utilities have decided to abandon plants in cases where they were clearly not required and have decided to continue construction in cases where plants are clearly needed or where the need is unclear. The latter situation may not lend itself to application of the prudence test. Further, if completed plants result in excess capacity, the used-and-useful test may more often form the basis of commission decisions than the prudence standard. However, prudence could be applied more in the future as state commissions expect that utilities will use state-of-the-art forecasting and capacity planning methods.

The prudent investment test, as applied by state commissions, has not been a test of whether the optimal or least-cost strategy was followed. Commissions do not necessarily require that the "best" investment decisions be made. They distinguish between the less-than-optimal investment decision that still may be prudent and the truly imprudent investment

decision. The prudent investment test provides state commissions with the rationale and the regulatory tool for making this distinction.

CHAPTER 4

THE PRUDENCE TEST AS A REGULATORY TOOL IN A PERIOD OF HIGHER RISK

For energy utilities, particularly electric utilities, the environment for investment decision making has been riskier over the last 10 to 15 years than in the past. These risks relate primarily to uncertainty about costs, especially capital and fuel costs; uncertainty about demand growth rates; and uncertainty about the supply of generation capacity that needs to be built for the future. Because the environment is more risky, the chance for error in utility planning is greater. Stated another way, the opportunity for making an imprudent decision has been much greater recently than before.

The riskier environment is likely to continue as energy markets adjust to a new and larger role in the national and world economies. For electric utilities, this role reflects the current high cost of fuels and electric generation capacity and the intervention (or withdrawal) of the national government in energy markets, as well as the increasingly international character of energy markets and cartels.

As a result, an electric utility may choose to construct capacity that turns out to be too costly or that runs on fuel that is either too expensive, prohibited, or embargoed. Also, the capacity may be unneeded, either because demand is less than expected or because the utility is required to take power from a PURPA qualifying facility or, perhaps in the future, from a regional power pool with a lower energy cost. Gas utilities also face greater risks as wellhead deregulation proceeds and competition with other energy sources becomes commonplace.

Not only is the opportunity for error greater today, but--because of very high capacity costs--the consequences of error are greater also. Who suffers the consequences--utility customers or utility investors--becomes a more important issue as the stakes grow higher.

Regulatory commissions, therefore, recently looked for a sound criterion for resolving this issue and found it in the prudent investment test. Clearly, however, the degree of detail in applying the test reported in chapter 3 goes well beyond that envisioned in the original Brandeis test reported in chapter 2. The prudence test is an evolving area of regulatory law, and the change in risk environment is a main cause of this evolution.

In this chapter, we treat the main features of today's riskier environment for electric and gas utilities, demonstrate that the consequences of error have been greater recently than in the past, and discuss the emerging role of the prudent investment test as a regulatory tool in this more risky environment.

A Riskier Investment Environment

The various factors affecting the risks associated with electric utility generating capacity investment might best be taken up according to whether they result primarily in capital cost uncertainty, demand growth uncertainty, or supply uncertainty. Of course, these are all ultimately related in that anything raising capital costs tends to dampen electric demand and to stimulate the supply of cogeneration capacity.

For gas distribution utilities also, the risks have increased, especially since the enactment of partial wellhead price decontrol in 1978, the main effects of which may be felt following the two stages of decontrol in 1985 and 1987. Nevertheless, the examples in this chapter deal only with electric utilities.

Capital Cost Uncertainty

As electric utilities plan coal and nuclear generating capacity, there is uncertainty about the ultimate cost of the completed plant. The costs of completing the average U.S. nuclear or coal power plant have escalated tremendously over the last 10 years. As shown in table 4-1, the average costs of constructing a nuclear power plant increased in constant 1982

TABLE 4-1

AVERAGE U.S. NUCLEAR AND COAL POWER PLANT CONSTRUCTION COSTS IN CONSTANT 1982 $/kW, WITHOUT ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

	Nuclear	Coal
Completed at the end of 1971	435	415
Completed at the end of 1978	1020	685
To be completed in 1982 or thereafter	2100	800-900

Source: Charles Komanoff, Komanoff Energy Associates, "Assessing the High Costs of New U.S. Nuclear Power Plants," a paper presented to the Seventh Annual National Conference of Regulatory Attorneys (Madison, Wisconsin, June 5, 1984), table 2.

dollars from $435 per kilowatt of capacity for nuclear plants completed at the end of 1971 to $2,100 per kilowatt of capacity for plants completed in 1982 or then under construction and to be completed thereafter. In other words, the construction costs of an average U.S. nuclear plant rose 482 percent over 10 years. The construction costs of completing a typical coal plant increased from $415 per kilowatt to $800-900 per kilowatt in constant 1982 dollars, an increase of approximately 100 percent. The entries in table 4-1 include construction costs only and do not include AFUDC. Because of the lengthening construction period for nuclear power plants and the recent high cost of capital for most projects, incorporating real AFUDC would further add to cost differences between old and new nuclear power plants, as well as to the differences between nuclear and coal power plants. According to one estimate, real AFUDC adds 30 to 40 percent to the cost of nuclear power plants and 15 percent to that of coal power plants to be completed in 1982 or thereafter.[1]

[1]Charles Komanoff, "Assessing the High Costs of New U.S. Nuclear Power Plants," a paper presented to the Seventh Annual Conference of Regulatory Attorneys (Madison, Wisconsin, June 4, 1984). Komanoff also estimates that real AFUDC adds approximately 8 percent and 6 percent, respectively, to the costs of the typical 1971 nuclear and coal power plants, and 11 percent and 9 percent to those of the typical 1978 nuclear and coal power plants.

This recent uncertainty in ultimate cost of generating unit construction is due, in part, to environmental regulation of coal units and safety regulation of nuclear units. In some cases, it may also be due, in part, to inadequate management attention to cost control procedures.

Environmental Regulation of Coal Units

Environmental regulation of coal units has affected and continues to affect the degree of utility confidence in capital cost estimates for such units. While national air quality control legislation in the United States was first enacted with the Clear Air Act of 1963, the most important air pollution control legislation was the Air Quality Act of 1967 and the Clean Air Act Amendments of 1970. They authorized the U.S. Environmental Protection Agency (EPA) to promulgate regulations with these objectives: (1) to achieve a level of ambient air quality that would protect the public health; (2) to achieve a level of an ambient air quality that would protect the public welfare from any known or anticipated adverse effects; and (3) to prevent the significant deterioration of air quality in those areas where the air is already clean. State agencies could also determine and enforce their own ambient air quality standards as long as they are as strict or stricter than the U.S. EPA standards.

At first, the promulgated EPA air quality standards did not specify the emissions of particular power plants as long as adjacent air quality remained within specific limits. The utilities were thus allowed to dispatch units using an intermittent control system that monitored the ambient quality and curtailed the "dirtiest" coal and oil plants during the periods of highest pollution.

Under the 1970 act, the U.S. EPA established "New Source Performance Standards" (NSPS) as the pollution standards for new plants. The EPA set the NSPS in terms of absolute ceilings on the volume of pollutants per unit of output. For coal plants, these ceilings were set at certain acceptable levels of sulfur oxides, nitrogen oxides, and particulates per million BTU.

The absolute ceilings for pollutants were set to reflect the "best available control technology" for removing the pollutants. However, under this set of regulations, fuel switching from high sulfur coal or oil to low sulfur coal or oil was permitted.

In 1977, the Congress enacted further amendments to the Clean Air Act. The 1977 amendments require that pollutants in a fuel must be reduced by at least a specific percentage, which usually requires scrubbers to be used, regardless of the quality of the fuel burned. For new plants being built in areas that already have "clean air" (PSD areas), installation of the best available control technology is required.

Many electric utilities engaged in litigation to block implementation of the NSPS standards. When these attempts failed, they were forced to consider how to comply. For plants not subject to the 1977 amendments, the choice for meeting the new standards was principally between raising the stack heights and switching from high to low sulfur coal or oil. For plants subject to the 1977 amendments, utility managers were forced to redesign their plants so that stack scrubbers, baghouses, or other pollution control technologies could be fitted in. A few utilities found that they needed to retrofit plants under construction with scrubbers.

Managers of electric utilities constructing coal plants adapted to these changes in environmental regulations in the 1970s and early 1980s. Problems associated with burning low sulfur coal were learned about through actual experience. Solutions were eventually found, but at a cost. Switching to low sulfur coal in a plant designed for high sulfur coal can adversely affect power plant performance and may require substantial investments in the boiler and boiler auxiliaries. Burning low sulfur coal may also require additional coal preparation and handling and may require an electrostatic precipitator for particulate emissions control. The extra expense for low sulfur coal is estimated to exceed $100 billion (at 1982 prices) during the period from 1980 to 1999.[2]

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[2]Eugene M. Trisko and Robert E. Wayland, "Acid Rain Control and Public Utility Regulation," Public Utilities Fortnightly, August 30, 1984, pp. 15-22.

The costs of complying with the EPA's environmental regulations have been great. For the plants that were subject to the more lenient regulations in effect until the 1977 amendments to the Clean Air Act, the cost of complying were relatively modest. However, for the plants subject to regulations implementing the 1977 amendments to the Clean Air Act, the costs of complying with the environmental regulations have been and continue to be substantial. As shown in table 4-2, (according to Canaday) the real increase in plant costs due to changes in environmental regulations explains the bulk of construction cost overruns in the construction of a typical new coal plant.[3] Thus changes in environmental regulations have affected the ability of management to estimate correctly the construction cost of a coal plant.

TABLE 4-2

TYPICAL COAL PLANT
CONSTRUCTION COST OVERRUNS, BY CAUSE
(Expressed as a Proportion of the Original Estimate)

Original Estimate	1.00
Unanticipated Inflation	.14-.38
Total AFUDC Increase	.10
Real Increase in Plant Costs Due to Changes in Enviromental Regulations	.40-.65
Total	1.64-2.13

Source: Henry T. Canaday, Construction Cost Overruns in Electric Utilities: Some Trends and Implications (Columbus: The National Regulatory Research Institute, 1980), table 20, p. 32.

[3]Henry T. Canaday, Construction Cost Overruns in Electric Utilities: Some Trends and Implications (Columbus: The National Regulatory Research Institute, 1980), pp. 30-32.

Future regulations are likely to contribute to further uncertainty in new coal plant costs. The most recent controversy before the Congress concerns the reduction of acid deposition ("acid rain"). Some of the legislative proposals before the last session of Congress, in effect, called for retrofitting emission control devices onto existing, pre-1976 coal plants. While utility managers have learned through experience how a scrubber system can be carefully matched to boiler equipment and how to maintain scrubber systems for successful operation, only a few utilities have experience in retrofitting scrubbers. As noted above, switching from high to low sulfur coal often lowers plant performance. For some coal-fired boilers, including most wet-bottom and cyclone boilers, burning low sulfur coal is not technically feasible. Emerging emission control technologies will give utilities new options including wet limestone, advanced dry scrubbing systems, and coal washing. Future options might also include inter-utility emissions trading, early plant retirements, and a return to dispatching plants so as to minimize pollution emissions.

The capital and operating cost consequences of possible new legislation are uncertain. To date, the Congress has merely provided for further study of the acid rain issue. But, future legislation in this area is decidedly possible, and this creates uncertainties for utility decision makers regarding the minimum cost approach for future coal-fired generation. Utilities cannot be certain whether they should refurbish an existing coal plant to extend its useful life. They cannot forecast with assurance the cost of future coal-fired generation, which may depend on the cost of low sulfur coal. Furthermore, utilities cannot be certain of the capital cost of a future coal plant. As a result, optimal capacity expansion plans are uncertain.

Safety Regulation of Nuclear Units

Safety regulation of nuclear units has affected and continues to affect the degree of utility confidence in capital cost estimates for such units.

At least at first, the Atomic Energy Commission (AEC), the predecessor agency to the Nuclear Regulatory Commission (NRC), deferred to nuclear industry judgment both as to design and protection of the public health and safety. As the nuclear power industry grew, it became apparent that a greater degree of regulatory oversight would be necessary to assure the public safety. As a result the AEC, and then the NRC, expanded the scope of its regulation during the 1970s and 1980s. The importance of assuring the public health and safety was reaffirmed by the Congress in 1974 when the regulatory functions of the AEC were transferred to the Nuclear Regulatory Commission.

It is well known that the NRC licensing process for a utility constructing a nuclear power plant is complex. Opportunities exist at several stages in the process for objection, delay, and possibly redesign of the plant; these factors contribute to capital cost uncertainty.

The process was summarized well in a recent report by the Office of Technology Assessment,[4] which deals with the uncertainties associated with nuclear power and from which we abstracted the following brief review of the regulatory process. The process involves a lengthy initial planning stage before the utility files a construction permit application with the NRC. The construction permit application includes (1) a Preliminary Safety Analysis Report, (2) an Environmental Report, and (3) antitrust information. On receipt of the construction permit application, the NRC staff reviews it for completeness and requests any additional information that may be necessary. When the staff is satisfied that the application is complete, the application is docketed. Then, the NRC staff issues a notice that it will hold a hearing on safety and environmental issues associated with the proposed plant before the Atomic Safety and Licensing Board of the NRC.[5]

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[4]Office of Technology Assessment, Nuclear Power in an Age of Uncertainty, (Washington, D.C.: U.S. Congress, Office of Technology Assessment, OTA-E-216, February 1984), p. 144.

[5]The following description of the NRC licensing process concentrates on procedures for assuring safety rather than those dealing with environmental issues.

In the meantime, the NRC's Office of Nuclear Reactor Regulation reviews the construction permit application and compares it to the standards in the NRC's "Standard Review Plan." The NRC Office of Nuclear Regulation suggests design changes to the utility. If the suggested design changes are rejected by the utility, the Office of Nuclear Reactor Regulation issues a Safety Evaluation Report documenting the suggested design changes that are disputed by the utility. The NRC's Advisory Committee on Reactor Safeguards also reviews and comments on the application. The NRC staff is free to supplement its Safety Evaluation Report with issues raised by the Advisory Committee on Reactor Safety. The review process that results in the preparation of the staff's Safety Evaluation Report, during the 1970s, took 1 or 2 years.

After the staff's Safety Evaluation Report (along with an associated Environmental Evaluation Report) is completed, a hearing is held on safety and environmental issues before the Atomic Safety and Licensing Board.[6] The hearing is adjudicatory in nature and involves direct testimony and cross-examination. After the hearing is completed, the Atomic Safety and Licensing Board issues its initial decision on whether to grant the construction permit. Upon appeal by one of the parties in the proceeding or on its own motion (an investigation sua sponte), the initial decision can be reviewed by the Atomic Safety and Licensing Appeal Board. Further, an appeal is possible to the Nuclear Regulatory Commissioners. In fact, since the accident at Three Mile Island, the initial decision on a construction permit must be approved by the Nuclear Regulatory Commissioners before it becomes final.

Once the construction permit is issued, actual plant construction begins.[7] During plant construction, the NRC staff conducts tests and

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[6]The hearing can be split into two hearings, one on environmental issues and another on safety issues.

[7]Site preparation has usually already taken place before the construction permit is issued. It usually occurs after the limited work authorization is issued.

construction inspections. There may be additional backfitting orders by the NRC during plant construction or further modifications to the design requested by the utility.

Only when the construction of the plant is completed is the plant design considered final. Then the utility files an application for an operating license. As a part of the application, the utility must submit a Final Safety Analysis Report, which sets forth details on the plant's final design and information concerning testing, operations, and plans for coping with emergencies.

The process for granting an operating license is similar to that of granting a construction permit, except that a public hearing is not mandatory, but optional. Current NRC regulations allow the NRC staff to issue a low power operating license, but the Nuclear Regulatory Commission itself must approve a full power operating license.

According to the Office of Technology Assessment (OTA), if the current regulatory process were to run smoothly a nuclear power plant could begin commercial operation 8 years or less after the construction permit is applied for, or 10 years after initial planning begins.[8] Why then has nuclear construction lead time increased so dramatically during the 1970s and 1980s? The OTA has identifed three principal sources of delay: (1) the utilities slowed down the construction of nuclear plants because of slackening demand and because of the high cost of capital; (2) nuclear plant size was being scaled-up during the 1970s, and plants were beginning construction with incomplete design information; and (3) the increased complexity of plant design made it more difficult for the utilities to manage the construction process.[9] There is a recognition by most analysts that NRC backfitting requirements do lead to construction delays and increased costs in nuclear power plants.

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[8]Offices of Technology Assessment, op cit., at pp. 146 and 147.

[9]Ibid., at p. 157.

The NRC's backfitting requirements provide that the NRC may order "the addition, elimination, or modification of structures, systems or components of the [nuclear] facility [under construction] after the construction permit has been issued [if the backfit will] provide substantial additional protection which is required for the public health and safety or the common defense and security."[10] The NRC changes its regulatory and design requirements during plant construction and operation by issuing bulletins, circulars, regulatory guides, and "voluntary" codes and standards. These NRC requirements are prescriptive in nature.

Currently, nuclear power plant designs must conform to major portions of Title 10 of the Code of Federal Regulations, including appendices, and all of the bulletins, circulars, regulatory guides, and voluntary codes and standards that may be invoked by the NRC. According to Canaday, a major portion of construction cost overruns can be traced to the increasing stringency of nuclear safety regulation.[11]

For example, the design-related modifications mandated by the NRC ultimately comprised 61 percent of the ultimate cost of the Davis-Besse Unit, completed in November 1977, as shown in table 4-3. However, as pointed out by Canaday, some portion of the construction cost overruns in a typical nuclear power plant are due to changes in scope and changes in safety rules that might be unnecessary and the result of "design/construction/management inefficiency." This Canaday defines as the increases that occur because (1) the initial design was poorly suited to the safety rules, (2) the construction had to be interrupted or deferred to accomodate these changes, or (3) there was a general breakdown in cost control by management due to the difficult construction environment.[12]

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[10] 50 C.F.R. Part 50.109(a).

[11] Henry T. Canaday, Construction Cost Overruns, pp. 21-27.

[12] Ibid., p. 26.

TABLE 4-3

CONSTRUCTION COST INCREASES FOR
DAVIS-BESSE NUCLEAR UNIT 1, BY CAUSE
(Expressed as a Proportion of the Original Estimate)

Original Estimate		1.00
Unit Size Increase from 800 MW to 906 MW		.13
Inflation in Labor and Materials		.63
Cooling Tower Addition		.08
Higher Than Anticipated Land Costs		.01
NRC Modifications and Their Chain Effects		
- Design Modifications	1.43	
- Loss of Productivity Due to Retrofitting the Design Changes	.53	
- Increase in AFUDC Due to Construction Delays and Cost Increments for the Design Changes	.81	
- Greater Cost for Training and Acceptance	.15	
	2.93*	2.93
Total Project Cost as Proportion of Original Estimate		4.78

* Entries may not add up to the total due to rounding.

Source: Authors' calculations, using data provided in Henry T. Canaday, Construction Cost Overruns in Electric Utilities: Some Trends and Implications, (Columbus: The National Regulatory Research Institute, 1980) table 12, p. 22. The ultimate source of the table is Christopher Bassett, "The High Cost of Nuclear Power Plants," Public Utilities Fortnightly, April 27, 1978.

Each new requirement adds to the complexity and hence to the uncertainty of nuclear power plant construction costs, and the number of NRC requirements is constantly increasing. According to Charnoff, in 1983 there were over 400 regulations and over 900 NUREGS (NRC policy reports) that a utility constructing a nuclear plant must comply with, compared with 250 regulations and 600 NUREGS in 1978, the year before the Three Mile Island accident.[13] Table 4-4 indicates how the number of nuclear power plant regulatory requirements in the form of rules, regulations, and policy

[13]Gerald Charnoff, "Why Management Did It All Right."

TABLE 4-4

THE APPROXIMATE NUMBER AND CUMULATIVE NUMBER OF FEDERAL NUCLEAR REGULATIONS, REGULATORY RULES, AND POLICY STATEMENTS PUBLISHED IN THE FEDERAL REGISTER CALENDAR INDEX FROM 1969 THROUGH OCTOBER 1983

Year	Approximate Number of Regulations	Cumulative Number of Regulations
1969	13	13
1970	42	55
1971	22	77
1972	28	105
1973	30	135
1974	25	160
1975	15	175
1976	20	195
1977	35	230
1978	30	260
1979	29	289
1980	40	329
1981	50	379
1982	49	428
1983	37	465

Source: Data derived from graphic presentations in Gerald Charnoff, "Why Management Did It All Right: Overregulation and Other Acts of God," a paper presented to the Seventh Annual National Conference of Regulatory Attorneys (Madison, June 4, 1984).

statements contained in the Federal Register has grown over the years. The increase in the number of regulatory requirements was particularly large following the 1976 Browns Ferry fire and the 1979 accident at Three Mile Island; plants being constructed following these events faced a significant number of back-fitting requirements. These, of course, are the plants that are being completed now.

The point of this section is to indicate that the uncertainties and risks that a utility faces in constructing a nuclear power plant in the 1970s and 1980s have increased substantially. While the opportunities for management error caused by back-fitting requirements have increased, it is not clear how much of the cost increases seen are due solely to regulatory

requirements and how much, if any, are the result of managerial imprudence. The authors of a recent NRC staff study found:

> that the root cause for the major quality-related problems in design and construction was the failure or inability of some utility management to effectively implement a management system that ensured adequate control over all aspects of the project. These management shortcomings arose in part from inadequate nuclear design and construction experience on the part of one or more of the key participants in the nuclear construction project: the owner utility, architect-engineer, nuclear steam supply system manufacturer, construction manager, or the constructor, and the assumption by some participants of a project role which was not commensurate with their level of experience.[14]

The NRC staff also found that shortcomings in the nuclear construction quality assurance program were the result of shortcomings in the utility's project management. The NRC staff stated that at least one reason for these shortcomings is the "lack of prudence" on the part of managers, that is, their failure to see how the required quality assurance program would fulfill management's need for feedback on the quality of plant.[15]

But, not all recently constructed nuclear power plants have the type of project management shortcomings in scheduling, cost, and quality of construction just identified. The NRC staff noted that at least three recently completed projects were successful from a quality standpoint: Vogtle, St. Lucie-2, and Palo Verde. The NRC staff specifically cited St. Lucie-2 as an example of how "even in today's regulatory environment, capable, experienced management with very complete design and with adequate project planning can construct a quality nuclear plant, at a reasonably

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[14]W. Altman et al., Improving Quality and the Assurance of Quality in the Design and Construction of Nuclear Power Plants (Washington, D.C.: U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, NUREG-1055 For Comment, May 1984), p. vii.

[15]Ibid., p. 3-23.

predictable cost, and in very little more actual construction time than is needed to construct a coal plant."[16]

It is not clear whether in the future, if any nuclear power units are built, the risks associated with cost uncertainty will be greater or less. The electric industry, the nuclear industry, and the NRC are considering measures to reduce these risks. Standardized plant designs, smaller units, and fundamentally safer designs are some of these measures. Further, in the NRC staff report, several proposals were made that might reduce the degree of cost uncertainty associated with future construction of a nuclear power plant. The proposals included (1) screening construction permit applicants for management competence and prior experience in nuclear construction, (2) conditioning construction permits on post-construction permit demonstrations by the applicant of its capability and effectiveness in managing a nuclear construction project, and (3) enhancing the NRC's resident inspector and team inspection program so as to address the issue of management capability and effectiveness on a routine basis, not just when the need for remedial action becomes apparent.[17]

Demand Growth Uncertainty

The historical peak demand growth of utilities through the 1960s was a relatively steady 7 percent per year, with demand growing at a rate of 7.7 percent between 1968 and 1972. The electric utility industry, on the whole, planned to continue adding capacity accordingly. However, energy market forces of the late 1960s and early 1970s, especially the 1973 oil embargo, caused the market price of oil and competing fuels to rise dramatically, which, in turn, drove up the price of electricity and suppressed consumer demand. As a result, peak demand grew at the rate of 1.5 percent in 1974 and 2.3 percent in 1975. This enormous reduction in peak demand growth caused the industry to begin to reexamine its peak demand growth forecasts.

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[16]Ibid., p. 3-22.

[17]Ibid., pp. iii, viii, ix.

As early as 1975, electric utility forecasters began to revise and reevaluate their demand forecasts to reflect the slowdown in industrial activity and the strong demand elasticities that were being realized. The forecasters lowered their 10-year peak demand growth rate projection from 7.6 percent in 1974 to 6.9 percent in 1975. Thereafter, the forecasters continued to adjust their projections downward to reflect the lower demand growth actually being realized. By 1978, peak demand for a 10-year period was projected to grow at 5.2 percent. Five years later, in 1982, the forecasters dropped their 10-year peak demand growth rate projection to 3.0 percent.

The projected growth rate has nevertheless exceeded the actual growth rate for most years since 1973.

Today, many of the electric generating units that were begun in the early 1970s are being completed. However, much of the demand projected in the 1970s did not materialize in the 1980s. Utilities are thus faced with the risks associated with either (1) bringing the plant into service and seeking a rate increase to cover its costs (causing rate shock and driving rates higher, which causes customers to conserve and to further reduce their demand), or (2) cancelling plants that are nearly completed.

The risks associated with demand growth uncertainty are likely to continue into the foreseeable future. Uncertainty exists concerning electricity demand even over the next 10 years. The U.S. Department of Energy released a major electricity policy report in June 1983, in which electricity demand was projected to increase between 2 to 4 percent annually through the year 2000, with a 3 percent load growth given as a reasonable median estimate.[18] This report resulted from an interagency project, chartered by the Cabinet Council on Environment and Natural Resources, with

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[18]"Critics of DOE Power Policy Report Hit Agency on Load Growth, Finances," Electric Utility Week, September 26, 1984, pp. 5-6; and "DOE Issues Electricity Policy Project Report," EPRI Journal, September 1983, pp. 31-33.

an interagency working group chaired by the Department of Energy. Yet, the 1984 10-year demand forecast by the North American Electric Reliability Council (NERC) is for substantially lower growth. It predicts an average annual summer and winter peak growth rate of 2.5 percent for the period 1984 through 1993.[19] Another U.S. Department of Energy forecast, not an independent forecast, but one based on the most recent NERC reports, is for a 2.27 percent summer and a 2.22 percent winter peak growth rate for the same period.[20] Independent forecasts can differ greatly from these. For example, two consultants, Siegel and Sillin, developed a 1982-1990 forecast about 3 years ago, which still receives considerable attention. It contends that electricity demand will grow at a relatively high annual rate of 4 to 5 percent.[21] Their growth forecast is based on sustained national economic growth and electricity's improved competitiveness, inferred from a recent fall in the real price of electricity. Thus, the electricity demand growth forecasts for the coming 10-year period vary substantially.

The uncertainty about future demand is due, in part, to uncertainty about the future prices for electricity and competing fuels and to uncertainty about how these prices affect electricity demand. Also, there is uncertainty about the various factors that contribute to demand in the industrial, residential, and commercial sectors.

Uncertainty exists, especially about how fast industrial demand will increase in the future.[22] Part of this uncertainty can be traced to

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[19]North American Electric Reliability Council, Electric Power Supply and Demand: 1984-1993 (Princeton: NERC, 1984).

[20]"DOE, NERC Prune their Load-Growth Estimates in New 10-Year Forecasts," Electric Utility Week, September 10, 1984, p. 7.

[21]John R. Siegel and John O. Sillin, "Rethinking Utility Strategy under Conditions of High Growth," Public Utilities Fortnightly, September 13, 1984, pp. 19-23; and "Utility Industry is Underbuilding Warn a Pair of Experts and DOE's Hodel," Electric Utility Week, March 26, 1984, pp. 5-6.

[22]Office of Technology Assessment, Nuclear Power, pp. 36-39.

recent economic performance of the industrial sector. One-half of all electricity used by industry is concentrated in the following specific industrial types, as identified by four-digit Standard Industrial Classification codes: primary aluminum, blast furnaces, industrial inorganic and organic chemicals not classified elsewhere, petroleum refining, paper mills, miscellaneous plastic products, industrial gas, plastics materials and resins, paperboard mills, motor vehicle parts, alkalis and chlorine, and hydraulic cement sectors. Several of these industries have recently undergone an economic slump. For example, industrial output of primary metals has recently decreased, and the production of several basic chemicals, which requires electricity, has grown only slightly or has decreased between 1974 to 1980. Industrial purchases of electricity made up 38 percent of the 2.1 billion kilowatt-hours sold in 1981, but industrial purchases fell as a result of the recession in 1982 to 35 percent of the total sold.

Furthermore, regardless of industry type, about half of all electricity used in industry serves a particular function: powering electric motors. Another 15 to 20 percent of all industrial use of electricity is for the electrolysis of aluminum and chlorine. Electricity use for these two functions is likely to decrease due to improvements in efficiency. A third function, electric process heating, now accounts for about 10 percent of industrial electricity. It has the potential for future growth, particularly as new electrotechnologies, such as plasma metals reduction, plasma chemicals production, and induction heating for casting and forging, become more widespread. However, demand growth in these areas assumes healthy domestic primary metals and chemical industries, and the health of these industries is in doubt. Additional uncertainty about industrial demand exists because of the potential for self-contained industrial cogeneration, that is, industrial cogeneration without sales to the outside electric grid.

Uncertainty about demand exists also for the residential and commercial sectors. For example, there is uncertainty about the future

rate of household formation. While penetration of air conditioning and electric heating has been increasing in recent years, more efficient air conditioning and electric heating have become available. Regarding future commercial demand for electricity, there is no reliable, current source of data on the expansion of commerical building square footage. However, it is known that between 1974 to 1979, commercial building square footage increased at a rate slower than the GNP, while commercial electricity sales increased at a rate higher than the GNP.[23] Whether these trends will continue is subject to question. Also, while electricity usage per square foot in commerical buildings may increase due to increasing usage of office automation equipment, there is also a potential for increased efficiency that may offset the projected increase, by balancing and maintaining commercial electricity loads of lighting, cooling, heating, refrigeration, and machinery.[24]

Clearly, demand forecasting can no longer be done with the ease experienced in the past. The uncertainty in future demand is greater today than in the past, when a 7 percent demand growth rate was almost taken for granted. Electricity demand is no longer tied solely to GNP growth, appliance end use, or any single variable--if it ever was. Rather, long term electricity demand is determined by an interrelationship between GNP growth, available and future end-use technologies, alternative energy sources (including cogeneration), and the price of other fuels, as well as the consumers' elasticities of demand.

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[23]Energy Information Administration, Nonresidential Building Energy Consumption Survey: 1979 Consumption and Expenditures Part 1: Natural Gas and Electricity, March 1983, as cited in Nuclear Power in an Age of Uncertainty (Washington, D.C.: U.S. Congress, Office of Technology Assessment OTA-E-216, 1984), p. 40-41.

[24]Office of Technology Assessment, Energy Efficiency of Buildings in Cities, OTA-E-192, February 1983, as cited in Nuclear Power in an Age of Uncertainty (Washington, D.C., U.S. Congress, Office of Technology Assessment, OTA-E-216, 1984) p. 41.

Uncertainties in the Need for New Plant

Even if future demand were known with certainty, it may be uncertain how much and what type of generation capacity a utility should construct to meet that demand.

The number, type, and timing of new power plants needed to maintain a given reserve margin needs to be determined. The need for new plants is affected by plant retirements, oil and gas back-out, and the loss of availability of generating capacity due to increasing power plant age. According to the Office of Technology Assessment (OTA), by the year 2000, there will be 20 gigawatts of existing power plant of 50 or more years in age, 105 gigawatts of existing power plant of 40 years or more in age, and 230 gigawatts of existing power plant of 30 years or more in age. Further, there are currently 152 gigawatts of oil and gas steam-generating capacity that may be backed out because of the high cost of fuel. Furthermore, if older generating units are not retired, their availability tends to decrease, thus increasing the need for new capacity. The variety of decisions on how to deal with each of these factors can increase the range of projections on the amount, type, and timing of capacity needed in the future.

For example, the OTA estimated that, even for a given demand, the amount of new capacity (beyond NERC's planned resources for 1991) needed by 2000 could vary considerably. OTA's estimates of the need for new plant are shown in table 4-5. In the case of a 2.5 percent annual demand growth rate, the OTA finds that the amount of additional capacity that needs to come on line by the year 2000 varies by a factor of two, depending on assumptions about retirements and oil back-outs.

Uncertainty about the required generation supply is also affected by the presence of cogenerators and small power producers because of the recent emphasis on developing alternative sources of energy. The principal legislation affecting the development of these alternative energy sources, broadly defined, is the National Energy Act that contains five bills, each

TABLE 4-5

NEW GENERATION CAPACITY NEEDED IN THE CONTINENTAL UNITED STATES BY THE YEAR 2000 BEYOND THE GENERATING CAPACITY PLANNED FOR 1991*

Level of Replacing Existing Plants	Capacity Needed at 1.5%/Year Demand Growth in gigawatts	Capacity Needed at 2.5%/Year Demand Growth in gigawatts	Capacity Needed at 3.5%/Year Demand Growth in gigawatts
Low: Replace all plants over 50 years old (50 GW)	9	144	303
Moderate: Replace all plants over 40 years old and back out 23 GW of oil and gas capacity (125 GW)	84	219	379
High: Replace all plants over 40 years old and back out 95 GW of oil and gas capacity (200 GW)	159	294	454

* The planned generating capacity for 1991, as reported by NERC, is 740 GW. The starting point for the demand calculation is the 1982 summer peak demand of 428 GW. The North American Electric Reliability Council defines "planned resources" as generating capacity installed, existing, under construction, or in various stages of planning; plus scheduled capacity purchases less capacity sales; less total generating capacity out of service in deactivated shutdown status.

Source: Office of Technology Assessment, Nuclear Power in an Age of Uncertainty (Washington, D.C.: U.S. Congress, Office of Technology Assessment, OTA-E-216, February 1984), p. 46.

of which contain policies that, when implemented, affect either the supply or demand of electricity. The bill of particular interest here because of its effect on electricity supply is the Public Utility Regulatory Policies Act of 1978 (PURPA). In Title II of PURPA, Congress requires electric utilities to buy power from qualifying cogeneration and small power production facilities.

To the extent that qualifying facilities offer power for sale, some new capacity constructed by utilities may be unnecessary. Because many

industries find the sale of cogenerated power at the utility's full avoided cost to be attractive, they file with the Federal Energy Regulatory Commission (FERC) as qualifying facilities. As shown in table 4-6, as of January 1, 1983, there were 119 filings for qualifying facility status. The rated capacities of these new qualifying facilities add up to 3,548 megawatts. While there is no guarantee that every qualifying facility filing will result in a cogenerator or small power producer that actually sells its power to the utility, if every qualifying facility were to operate at its rated capacity, the power produced by cogenerators at the beginning of 1983 would be roughly equivalent to that of 3 or 4 large base load units. Many new cogenerators have filed since then. The FERC staff once estimated that by 1995 there would be 16,600 megawatts of cogenerated electricity, of which 5,900 megawatts would have been induced by PURPA.[25]

The actual amount of power that will be supplied by cogenerators in the future is uncertain. Because of this uncertainty, electric utility managers cannot build new plant without facing the likelihood that the plant will not be needed because a potential cogenerator actually begins to generate power. On the other hand, if the electric utility fails to build a plant (with a lengthy construction lead time) and counts on the potential cogenerators to generate power, the cogenerators may not have power to sell when it is needed. Instead, the potential cogenerator may determine that selling cogenerated electricity to the utility is not in the cogenerator's own best interest; an alternative investment might be more profitable for the cogenerator. The electric utility would then need to take an alternate course of action, perhaps raising the avoided cost rates offered to cogenerators. The utility might then find that the new rate being paid to the cogenerator is higher than the cost of building a plant itself would have been.

The utility decision to build or not build must be prudently made. The point here is that risks exist that did not exist before and that opportunities for imprudent decision making are greater than in the past.

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[25]45 Fed. Reg. 23,608 (1980).

TABLE 4-6

FILINGS FOR QUALIFYING FACILITY STATUS BY STATE AT THE FEDERAL ENERGY REGULATORY COMMISSION THROUGH JANUARY 1, 1983*

State	Number of Filings	Rated Capacity (in Kilowatts)
Alabama	1	37,400
Arizona	1	375
California	55	1,009,975
Connecticut	1	150
Florida	13	383,120
Georgia	2	76,600
Hawaii	1	19,400
Idaho	1	5,000
Kansas	1	33,730
Louisiana	1	100,000
Maine	1	46,700
Massachusetts	3	583,400
Michigan	1	22,400
Mississippi	4	7,177
Missouri	1	80,000
New Hampshire	1	1,800
New Jersey	2	35,300
New York	1	100
North Carolina	2	58,000
North Dakota	1	9,000
Ohio	1	16,500
Oregon	2	100,000
Pennsylvania	2	55,500
Tennessee	7	27,228
Texas	4	750,000
Virginia	6	55,507
Washington	2	29,000
Wyoming	1	5,000
TOTALS	119	3,548,362

* There was at least one filing by a facility in Nebraska for which no data are available.

Source: Wooster, "Cogeneration: Revival Through Legislation" 87 Dickinson Law Review 758 (1983).

Greater Consequences of Error

Not only are the opportunities for imprudent decision making greater than in the past, but the consequences of an imprudent decision are also greater--both in absolute and relative terms. To show that the consequences are significantly greater today for electric utilities, we compare the present and past effects of a finding that a decision to invest in a generating unit is imprudent.

In table 4-7, construction expenditures and construction work in progress are compared with the value of net electric utility plant. The table shows in column 1 the annual production (i.e., generation-related) construction expenditures of U.S. privately-owned electric utilities from 1944 to 1983. Column 2 shows the annual total construction expenditure for these years. Column 3 gives electric construction work in progress for privately-owned utilities; unfortunately these data are available only for the years 1967 to 1983.

In column 4 are the values of net electric utility plant for each of the last 40 years. These values are intended to provide a good estimate of the total value of private investment in providing electric service and hence to permit comparison of the relative size of the investment in construction over the last 4 decades.[26]

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[26]Net electric utility plant is used because it is the best data available for the entire time period that indicates the value of the investment in capital equipment for providing electric service. Net electric utility plant is electric plant less accumulated provision for depreciation and amortization. Because of the potentially distorting effect that including nuclear fuel would have in comparing earlier with later years, net nuclear fuel is not included in table 4-7. Some categories of utility investment not included in net electric utility plant are "other property and investment," total current and accrued assets, and total deferred debits. These categories of assets are not typically a part of electric utility plant in service. Total construction expenditures, excluding nuclear fuel, represent the amount spent on constructing generation, transmission, distribution, and other general plant each year. Construction expenditures include an allowance for funds used during construction (AFUDC) where appropriate.

TABLE 4-7

CONSTRUCTION EXPENDITURES AND CONSTRUCTION WORK IN PROGRESS OF U.S. PRIVATELY-OWNED ELECTRIC UTILITIES AS A PERCENTAGE OF NET ELECTRIC UTILITY PLANT, 1944-1983

Year	(1) Annual Production Construction Expenditures ($ x millions)	(2) Annual Total Construction Expenditures ($ x millions)	(3) Electric Construction Work In Progress ($ x millions)	(4) Net Electric Utility Plant ($ x millions)	(5) Annual Production Construction As A Percent Of Net Electric Utility Plant (%)	(6) Annual Total Construction As A Percent Of Net Electric Utility Plant (%)	(7) Construction Work In Progess As A Percent Of Net Electric Utility Plant (%)
1944	90	240	N.A.	9,620	1	2	N.A.
1945	110	350	N.A.	9,647	1	4	N.A.
1946	170	650	N.A.	9,660	2	7	N.A.
1947	425	1,235	N.A.	10,575	4	12	N.A.
1948	750	1,830	N.A.	12,079	6	15	N.A.
1949	1,000	2,190	N.A.	13,758	7	16	N.A.
1950	890	2,050	N.A.	15,104	6	14	N.A.
1951	920	2,134	N.A.	16,579	6	13	N.A.
1952	1,251	2,599	N.A.	18,442	7	14	N.A.
1953	1,391	2,876	N.A.	20,733	7	14	N.A.
1954	1,280	2,835	N.A.	22,815	6	12	N.A.
1955	1,064	2,719	N.A.	24,579	4	11	N.A.
1956	1,029	2,910	N.A.	26,524	4	11	N.A.
1957	1,647	3,679	N.A.	29,212	6	13	N.A.
1958	1,879	3,764	N.A.	31,893	6	12	N.A.
1959	1,519	3,383	N.A.	34,243	4	10	N.A.
1960	1,342	3,331	N.A.	37,036	4	9	N.A.
1961	1,183	3,000	N.A.	38,975	3	8	N.A.
1962	1,057	3,037	N.A.	40,584	3	7	N.A.
1963	1,083	3,240	N.A.	42,392	3	8	N.A.
1964	1,115	3,558	N.A.	44,184	3	8	N.A.
1965	1,228	4,055	N.A.	46,691	3	9	N.A.
1966	1,640	4,941	N.A.	49,843	3	10	N.A.
1967	2,479	6,204	4,418	54,239	5	11	8
1968	3,102	7,118	5,896	59,393	5	12	10
1969	3,897	8,357	7,732	65,613	6	13	12
1970	5,249	10,047	10,330	73,451	7	14	14
1971	6,537	11,857	13,531	82,829	8	14	16
1972	7,917	13,463	16,623	93,341	8	14	18
1973	8,855	15,059	20,246	105,794	8	14	19
1974	10,094	16,702	22,846	117,986	9	14	19
1975	10,094	15,650	26,319	128,551	8	12	20
1976	11,964	17,360	31,717	141,404	8	12	22
1977	14,416	20,281	36,484	156,124	9	13	23
1978	16,132	22,937	42,476	172,584	9	13	25
1979	18,281	25,481	53,991	192,240	10	13	28
1980	19,238	27,011	60,440	211,909	9	13	29
1981	20,912	29,124	69,439	231,940	9	13	30
1982	25,339	33,602	82,026	255,171	10	13	32
1983	24,935	33,816	98,356	273,073	9	12	36

Sources: Authors' calculations based on data from Statistics of Privately-Owned Electric Utilities in the United States: Summary Sections for 1952, 1958, 1959, 1967, 1977, and 1980 (Washington, D.C.: Federal Power Commission); Financial Statistics of Selected Electric Utilities, 1982 (Washington, D.C.: Department of Energy, Energy Information Administration, 1984); Historical Statistics of the Electric Utility Industry Through 1970 (New York City: Edison Electric Institute, 1974); Edison Electric Institute Statistical Year Book of the Electric Utility Industry, 1972, 1978, 1979, 1981, 1982, 1983 (Washington, D.C.: Edison Electric Institute); and Financial Review: An Annual Report on the Electric Utility Industry (Washington, D.C.: Edison Electric Institute, 1984). Because various sources of data are used in the table, there are minor discrepancies in the data, as follows. From 1944 through 1959, the data sources for net electric utility plant are the Statistics for Privately-Owned Electric Utilities in the United States, published by the Federal Power Commission. Beginning in 1960, the sources for net electric utility plant data are the Statistical Year Book(s) of the Electric Utility Industry published by the Edison Electric Institute. Thus, there may be a slight discontinuity in the data between 1959 and 1960. The net electric utility plant data for 1948 through 1959 are based on estimates by the Federal Power Commission. The net electric utility plant data for 1944 through 1947 are estimated by the authors based on the data in the Statistics of Privately-Owned Electric Utilities in the United States: Summary Section for 1952. The annual total construction expenditures and annual production construction expenditures exclude data for Alaska and Hawaii prior to 1961. Net electric utility plant excludes data for Alaska prior to 1958 and excludes data for Hawaii prior to 1959. The discrepancies in the data, however, do not affect the general trends shown in the table. N.A. indicates that data are not available.

Notice that total construction expenditures as a percentage of net electric utility plant (column 6) have not changed greatly in the post-World War II years. From 1947 to 1959 the electric utility industry made annual construction expenditures ranging from 10 to 13 percent of its net electric utility plant value. Only in the years 1960 through 1965 were annual construction expenditures less than 10 percent of the value of the net electric utility plant, perhaps because in these years many oil or gas burning peakers were installed to meet peak demand at low investment cost. Even then, the expenditure rates were between 7 and 9 percent. Since 1969, capital expenditures have stayed between 12 and 14 percent of net electric utility plant. Perhaps surprisingly, despite the claims that utility investments are at historical highs, at least this one measure of investment shows the relative stability of the electric utility industry's construction expenditure program during the post-World War II years.

Consider, however, the annual production construction expenditures as a percentage of net electric utility plant. It has risen in recent years. Annual production construction expenditures ranged from 1 percent to 7 percent of net electric utility plant during the years 1944 through 1970, with a (straight) average value of 4.5 percent. However, from 1971 through 1983 annual production construction expenditures ranged from 8 to 10 percent of net electric utility plant, averaging 8.8 percent--about double the prior average. Production construction expenditures crossed over in 1971, from making up half or less of the annual total construction expenditures to making up more than half--up to three-fourths of these investment expenditures. Hence, while total construction has remained relatively stable in percentage terms, the generation portion of construction investment has increased significantly. It is this portion that is most at risk in recent prudence inquiries.

These data relate to investment expenditures in a single year. If these industry percentages are carried over to an "average" utility, then before 1971 a typical electric utility invested each year in generation construction an amount equal to about 4.5 percent of its net plant. Under the simplifying assumption that it built one unit at a time, the investment

in a unit with a 4-year construction period was 18 percent (4.5% x 4 years) of net plant.

Since 1971, not only has the cost of annual generation construction increased in absolute terms, and not only has the annual cost increased as a percentage of net plant (up to 8.8 percent), but construction times have increased also. For example, average construction durations for nuclear units increased from slightly less than 4 years for units completed in 1971 to about 8 years in 1978, roughly the midpoint of the 1971-1983 period.[27] Construction times for nonnuclear units and for periods well before 1970 were less than 4 years. Construction periods for large coal-fired units have been increasing, and nuclear construction now takes well over 10 years.

During the 1971-1983 period, if the average utility invested 8.8 percent of net plant in a generating unit each year for 8 years (ignoring year-to-year variations in net plant), the investment in the unit amounts to 70 percent of the company's net plant. Clearly, the stakes are higher today than in the past.

In reality, a utility's construction program is usually smoother than this, providing for some plant addition to rate base every few years and reducing the exposure of construction investment. The value of construction work in progress (CWIP) is a better indicator of the risks that the electric utility industry faces in constructing new plant. It measures the cumulative investment not yet in rate base up to any given year. However, data on CWIP are not available for years before 1967. As can be seen in column 3 of table 4-7, the investment tied up in electric construction work in progress increased from $4.4 billion in 1967 to $98.3 billion in 1983.

The reasons for this increase in cumulative total construction expenditures include higher materials and labor costs, the lengthening of construction periods, and the high rate of inflation in the late 1970s and very early 1980s with the consequent high real cost of capital during these

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[27]Canaday, Construction Cost Overruns, p. 24.

years. As a result, not only are direct costs high, but the cost of capital is high, leading to a growing proportion of AFUDC in construction expenditures. The high AFUDC is compounded because of the increasingly long construction periods required to build a large, complex power plant. The data in column 3 show that the consequences of an imprudent decision have increased in absolute terms.

The consequences of an imprudent decision have also increased in relative terms. Column 7 of table 4-7 shows that CWIP as a percentage of net electric utility plant has increased continuously from 1967 through 1983, from 8 percent to 36 percent. This means that in 1983, the electric utility industry had 36 percent of the value of its net electric plant in service tied up in construction work in progress.

Assume that our average electric utility company has a capital structure of 40 percent equity and 60 percent debt. In such a situation, the average company would have "bet" nearly its entire stockholder equity value on the construction work in progress. Should the plant or plants under construction be kept entirely out of rate base due to imprudence, the consequences for the company would obviously be much more severe today than in the past.

A Regulatory Tool for Allocating Risk

As a result of these greater risks and greater consequences of risk, many current electric utility investment decisions expose stockholders or ratepayers to the possibility of severe financial losses. State utility commissions feel torn between two obligations. On the one hand, they want to keep utilities financially sound so they can continue to provide reliable service to customers. On the other hand, they are obliged to set rates at a level that is reasonably related to the costs required to provide service.

The first obligation implies that, since certain reasonable risk-taking is a part of any business, ratepayers should, as part of the cost of

service, bear the costs associated with reasonable risks that do not "pan out." The second obligation implies that ratepayers ought not to bear unreasonable investment risks or levels of risk, which are normally borne by stockholders and for which they are compensated in the form of dividends when the risks pay off.

When the amount of risk was low, that is, when the utilities rarely "lost their bets," or when the impact on rates of a poor investment decision was small, commissions either did not need to choose between these obligations or could often choose in favor of financial soundness without significantly affecting the level of rates. Recently, however, commissions have increasingly been forced to choose between these two obligations in situations where large investment values are at stake and where a decision, one way or the other, will have a large impact on either investors or customers.

In response to these forces, commissions have searched for a principle for guiding decision making, a principle with some historical precedent in utility ratemaking and a principle that does not necessarily require an "all or nothing" decision in favor of one side, but can allow some appropriate sharing of the risk between investors and ratepayers. The concept of prudence is emerging as that principle.

Two types of risk can be identified: systematic and unsystematic risk. Systematic risk is the risk that affects all companies, such as risks arising from the general economy and the movement of financial markets as a whole. Unsystematic risk is the risk related to the circumstances of a particular company. In other words, unsystematic risk is the portion of total investment risk unique to the particular company.[28]

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[28]See generally Alvin Kaufman et al., Unplanned Electric Shutdowns: Allocating the Burden (Columbus: The National Regulatory Research Institute, 1980) and specifically Christopher C. Pflaum and J. Kenton Zumwalt, "Investment Risk Evaluation: The Special Case of the Regulated Firm," The Proceedings of the Fourth NARUC Biennial Regulatory Information Conference (Columbus: The National Regulatory Research Institute, 1984).

Without necessarily using these terms, many commissions choose to have ratepayers bear systematic risk and utility investors bear unsystematic risk. Indeed, commissions are prone to have ratepayers share the risks that only systematically affect the entire electric industry or gas industry--or sometimes the risks that systematically face just companies in a particular geographic region. The prudent investment test is, in such cases, a tool for identifying the unsystematic risk associated with a utility's investment in a new plant. The prudent investment test has usually operated so as to allow prudently incurred capital expenditures into the rate base. In the case of an abandoned electric plant, for example, the prudent investment test, as recently applied by most state commissions, provides for the eventual recovery of prudently incurred expenditures through amortization in order to protect utility investors from exposure to the systematic risk of generally declining electricity demands. If the commission believes that management shares some specific responsibility, the test provides the possibility of risk sharing: the unamortized balance typically is not allowed into rate base in most states.

In the case of excessive construction costs also, the concept of prudence permits a division of risk and responsibility between investors and customers. Overruns are due, in part, to systematic factors such as increased interest rates. But some other factors that have led to construction cost overruns are not attributable solely to a systematically riskier environment, but rather, in part, to managerial failure. With the greater stakes involved in the construction of larger nuclear and coal power plants, utility managers in some cases could have better controlled the costs, the scheduling, and the quality of construction. When utility managers fail to control these, the prudent investment test allows the regulator to eliminate from rates the investment costs that were due to managerial imprudence.

Yet the prudent investment test need not be applied so strictly that utilities become liable for every delay and error that occurs, whether or not the utility management is at fault. If a utility plant has a

construction cost overrun, for example, because of an unforseeable change in regulatory policy such as a Nuclear Regulatory Commission regulation requiring backfitting, commissions usually allow a utility to recover the full costs of its investment in the plant. This seems justified because in a more competitive environment each competitor building a similar plant would have been required to backfit its plant to meet the new regulatory requirement also. All similarly situated competitors would raise their prices to cover the costs of the backfit. If such competitors, given the facts and circumstances known or foreseeable at the time, would have chosen to build such a plant and incur such a cost, then most regulators believe that it is appropriate to allow a utility to recover its investment in the plant--even if the investment decision turns out to be wrong.

In other words, most regulators do not choose to hold utility managers responsible for systematic or industry-wide risks that affect the electric utility industry as a whole. Instead, state commissions often use the prudent investment test to hold a utility harmless, except for the consequences of decisions that are unreasonable based on the known or the foreseeable.

Used in this manner, the prudent investment standard is a more flexible standard than the used-and-useful standard, which is often interpreted as an "all or nothing" standard for rate base treatment of investments.

The prudent investment test is currently being applied more often than in the past because of an increasingly risky environment. Because this riskier environment is likely to continue and perhaps become more risky in the future, it is also likely that the prudent investment test will be applied frequently, perhaps more frequently, in the future. Hence, the prudence test will grow more important as a regulatory tool, and it is important to examine some of the consequences of strict commission use of this tool.

CHAPTER 5

SOME LONG TERM CONSEQUENCES OF APPLYING THE PRUDENCE TEST STRICTLY

As we have seen, the prudence test can act in favor of utilities, providing compensation for prudently incurred investment expenses that end up being unneeded. It can also act against utility interests where large expenditures are based on an imprudent decision. In the second case, strict application of the prudent investment test by state commissions may have any of several unintended consequences. A discussion of some possible consequences of applying it routinely and universally, excluding large utility expenditures from rate base, is the subject of this chapter.

Many utility representatives say that under strict application of the prudence test utilities will stop investing in new plant, resulting in no growth in electric capacity. In order to avoid this, some assert that commissions must guarantee cost recovery to utilities planning new capacity. Many consumer representatives admit that strict application of the prudence test could result in utility bankruptcy, but argue that bankruptcy can lower rates appropriately without affecting the quality of service. Others claim that bankruptcy would result in loss of service to customers or in poor service at high rates--accompanied by loss of state commission authority to deal with the situation.

There is a perhaps more likely consequence of future strict application of the prudence test, which lies between the two extremes of no growth and bankruptcy. It is that the relationships between utilities and other parties involved in capacity development may change. The investment community may come to view the utility business as a permanently high risk business, resulting in an increase in the cost of capital for this capital-intensive sector. The relationship between managers and utility stockholders may change as investors hold managers legally responsible for decisions found to be imprudent by state commissions. Managers, architect-engineers, and construction contractors may develop more formal, "arm's

length" relationships. Or utilities and state commissions may become closer, less "at arms lengths," as they become partners in assessing the need for power and determining the best way to meet that need.

In the sections that follow we explore further the arguments about some of these possible consequences, considering utility investment policy, utility bankruptcy, and utility relationships. (Discussion of the relationship between utilities and commissions is deferred to chapter 6.)

Utility Investment Policy

Here we consider the probable consequences of various regulatory environments on a utility's investment behavior, especially in the presence of business risk such as uncertain future demand. These environments relate to the degree of regulatory strictness in applying the prudent investment test. We examine the impacts by means of an electric utility example.

Consolidated Power Example

Consider the problem of forecasting electricity demand, an especially knotty problem for energy utilities since the Arab oil embargo of 1973. Suppose that the year is 1986 and that an electric utility called Consolidated Power needs 10 years to build a new plant. Given an expected marginal cost of power, the utility would do a demand forecast for 10 years into the future, to the year 1996. Ideally, this demand forecast for each year would contain two numbers: the expected demand at an assumed marginal cost, and the standard deviation of the expected demand. We will study the impact of risk in the next few subsections by generalizing from a specific example.

Assume our hypothetical utility, Consolidated Power, does such a demand forecast for the year 1996, 10 years into the future. In the example we assume that the state commission and the utility have agreed

that load growth will be handled by constructing relatively small 400-MW units. The most beneficial way to build several small generating units is to wait several years after starting one unit before starting another. In order to keep the example simple, we assume that an unexpected rise in forecasted long term demand requires that several units be constructed as quickly as possible in order to alleviate an expected power shortage and that they all come on line in the same year, 1996. Also for simplicity, we assume that the cost of capital is 10 percent and that Consolidated intends to construct generating units that each cost $62.735 million per year for 10 years. With accrued interest (actually allowance for funds used during construction) at 10 percent, each unit will add $1 billion to the rate base in 1996, when the units are operational. Further, we assume that these units are expected to last 30 years and then will be costlessly scrapped;[1] hence each unit costs the users $.1061 billion per year for 30 years. Assume also that when the demand forecast is adjusted for the number of units needed at a standard load factor, expected demand is 4.0 units, the standard deviation is 1.0 unit, and the distribution is normal. Assume that if demand is between 3.50 and 4.49, then four new units will be built; between 4.50 and 5.49, five units; and so on.

The probability of demand for each number of units between zero and eight is given in table 5-1. The use of probability reflects our uncertainty in 1986 about the need for power in 1996. The table shows, for example, that the probability that four new units will be needed in 1996 is about 38 percent. The probability that four or fewer units will be required is about 69 percent. Conversely, the probability that more than four units will be required is about 31 percent (100-69). The probability distribution in this example has a standard deviation that is 25 percent of the mean estimated new capacity. This standard deviation-to-mean ratio seems plausible for an industry with generating units that take 10 to 12 years to construct, because utilities must forecast demand growth about

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[1]Of course, if the plants are nuclear, there is a substantial cost to decommissioning them. See Robert E. Burns et al., Funding Nuclear Power Plant Decommissioning (Columbus: The National Regulatory Research Institute, 1982).

TABLE 5-1

CONSOLIDATED'S NEED FOR NEW UNITS

Number of New Units Required	Probability	Cumulative Probability
0	.0002	.0002
1	.0060	.0062
2	.0606	.0668
3	.2417	.3085
4	.3830	.6915
5	.2417	.9332
6	.0606	.9938
7	.0060	.9998
8	.0002	1.0000

Source: Authors' calculations

12 years into the future. This ratio may even be low in light of the demand forecasting errors that were made during the 1970s.

After the utility determines that new capacity must be added, it collects estimates of construction costs and times for various technologies, and decides on the least-cost expansion plan with acceptable reserve capacity and reliability each year. Typically, a utility might require a reserve margin 20 percent above peak load to achieve a reliability of one generation-related power outage in 10 years. Depending on the state, the utility might then take this demand forecast and the least cost expansion plan to its state commission or other state agency and request that the state agency agree, in a power siting or certificate of need proceeding, that this least cost expansion plan would be a prudent investment.[2]

[2]Some thirty-two state commissions report making a needs determination for plant investment as part of a certification of convenience and necessity, a power plant siting hearing, or some other process. In addition, most commissions must grant approval for issuance of new securities to finance construction. The degree to which these proceedings constitute a formal commission agreement with the reasonableness or prudence of the construction decision varies considerably from state to state. See R. J. Profozich et al., Commission Preapproval.

In all the following analysis, we assume that the commission and the utility agreed at the time that construction began that the proposed construction was a prudent way to meet projected demand. We call projects that a commission or other state agency agreed were prudent before construction began "prudent ex-ante," or prudent before the fact. The analysis concentrates on the consequences of judging whether an investment is prudent after the project is completed (or even under construction). In other words, we analyze the consequences of a commission denying the addition of plant to the rate base because the decision to complete the project is no longer prudent, even though the decision to initiate construction was prudent. The commission would then be judging whether a project is "prudent ex-post," or prudent after the fact.

Three Regulatory Environments

We will examine the utility's investment strategy under three regulatory environments, or rules, for applying the prudence test to candidate investments for rate base treatment.

All-Investments Rule

Consider a regulatory environment where all investments that are prudent ex-ante are added to the rate base. Suppose all investments that are prudent ex-ante have a zero net present value (NPV) to the utility's investors. That is, regulation acts to prevent investors from earning any profits above those available from other similar investments and also prevents any losses that would detract from that "normal" level of profit. Then Consolidated will invest in whatever least-cost expansion plan the commission judges to be prudent ex-ante. From table 5-1, the socially optimal investment is $4 billion (four units at $1 billion each) if the social cost of underinvestment equals the social cost of overinvestment. If the commission agrees that beginning construction of four units at a projected cost of $4 billion is prudent ex-ante, then Consolidated will begin construction of the four units, a project with an expected zero NPV.

If demand turns out to be less than forecasted, this regulatory environment causes a utility to make the socially optimal decision about abandoning plants, which is to ignore sunk costs. Suppose that Consolidated has already spent $600 million on a nuclear power plant and needs to spend $400 million more to complete it. The socially optimal decision is to complete the plant only if the present value of marginal income (revenues less variable costs) from completing the plant exceeds $400 million. Consolidated uses this decision process because it will recover the $600 million in sunk costs that it prudently invested in the plant regardless of whether it finishes the plant.

If demand turns out to exceed four units and $4 billion, Consolidated would begin constructing additional plants.

The commission does not have to trust Consolidated to abandon partially completed, unneeded plants. It can require periodic reviews of the demand forecast and the least-cost expansion plan. If demand turns out to be less than previously forecast, the commission can decide that abandoning a plant is prudent and continuing construction is not. If it decides that the sunk costs of a partially completed plant can be added to the rate base, but the additional costs needed to finish the plant cannot be added to the rate base, the utility would choose the zero net present value project (to abandon the plant) rather than the negative net present value project (to continue construction).

The major drawback of this regulatory environment is that there are no profit incentives to encourage efficiency or good management. This lack of incentive provides a strong motivation for the prudent investment test.

Operational-Investments-Only Rule

Consider next a regulatory environment where neither abandoned plants nor plants under construction can be added to the rate base, but completed

operations plants can always be added. This change in the regulatory environment alters the investment incentives for Consolidated when changes in economic conditions cause demand to be less than previously forecast. No matter what demand turns out to be, Consolidated will always complete a plant once construction has begun because Consolidated has no other way to recover money spent on an partially constructed plant. This regulatory environment provides short run incentives to overinvest in the sense that plants are completed even when it is socially optimal to abandon them.

Operational-and-Needed-Investments-Only Rule

Most commissions recognize the perverse incentives to complete unneeded plants if only operational plants can be added to the rate base. Statutes or court decisions in several states require that only needed and operational plants may be added to the rate base. In other words, the state or the commission reserves the right to judge that an investment that was prudent ex-ante is not prudent ex-post if a change in economic conditions reduces demand.

In the following analysis we assume that commissions distinguish between short term fluctuations in demand due to weather and business cycles and long term changes in demand due to changes in technology, demographics, and relative energy prices. In this analysis, commissions refuse to add a plant to the rate base only if the plant is unneeded due to a change in long term demand. In the short run, this regulatory environment causes plants that are unneeded ex-post to be abandoned, as intended. The following analysis examines the long run effects of this regulatory environment.

If a commission wishes not to add investments to the rate base that are not needed ex-post, it may favor a utility construction plan consisting of several small units rather than one large unit. Suppose that a utility could satisfy forecast demand with four small units or one large unit.

Suppose actual demand turns out to be only 75 percent of the forecast demand. The commission can rule that one of the four units is unneeded and cannot be added to the rate base, but might find it awkward to rule that only 75 percent of a large unit is needed and that only 75 percent of the cost of construction can be added to the rate base, because the unit cannot be operated, of course, until 100 percent of the construction is complete.

In the case we consider here, the commission will approve only prudently incurred costs for the prudent ex-post capacity expansion. However, Consolidated uses net present value analysis to determine the financial consequences of investing. Table 5-2 shows the expected NPV of building from zero to four new units given this regulatory environment and Consolidated's demand forecast of table 5-1. In table 5-2, the first column shows several possible levels of need for new units, from zero to four or

TABLE 5-2

EXPECTED NET PRESENT VALUE TO THE COMPANY OF BUILDING N NEW UNITS
(IN BILLIONS OF DOLLARS)

Number of New Units Required	Probability	Gains or Losses from Building N Units				
		4 Units	3 Units	2 Units	1 Unit	0 Units
0	.0002	-$4	-$3	-$2	-$1	0
1	.0060	-$3	-$2	-$1	0	0
2	.0606	-$2	-$1	0	0	0
3	.2417	-$1	0	0	0	0
4-8	.6915	0	0	0	0	0
Expected NPV		-$.3817	-$.0732	-$.0064	-$.0002	0
Probability of Shortage		.3085	.6915	.9332	.9938	.9998

Source: Authors' calculations

more, and the second column shows the probability of each level of need. As mentioned with table 5-1, the probability that demand turns out to be for three units, for example, is 24.17 percent. The remaining columns show the gain or loss to Consolidated for building zero to four units at each level of actual demand. For instance, the fourth column shows that if Consolidated builds three units and demand turns out to be for two units, then Consolidated loses $1 billion because two units are granted rate base treatment and one, costing $1 billion, is not.

The next to last row of table 5-2 shows the expected net present value of each of the five investment plans and is computed by summing for each column the products of each gain or loss and the probability that the gain or loss occurs. For instance, suppose Consolidated builds two units. Then there is a .0002 probability that demand will turn out to be for no units, in which case Consolidated will lose $2 billion, and there is a .0060 probability that demand will turn out be for one unit, in which case Consolidated will lose $1 billion. Consolidated neither gains nor loses if demand turns out to be for two or more units. The expected NPV of building two units is

$$(-\$2,000,000,000 \times .0002) - (\$1,000,000,000 \times .0060) = -\$6,400,000,000$$

which is shown in the table as -$.0064 billion.

The final row in table 5-2 is the probability that building N units will result in a power shortage. Here, a power shortage refers to a situation in which the utility's reserve margin falls below the target value. For instance, if three units are built and the utility follows these investment rules, there is a 69.15 percent probability that there will be a capacity shortage (demand exceeds three new units with a probability of 69.15 percent).

Consolidated expects to lose $382 million if it builds the socially optimal four units, but the expected loss declines as the number of units it builds declines. Logically, Consolidated would choose to construct no new units because this is the only investment strategy with a nonnegative NPV. Under this strategy the probability of a power shortage is 99.98 percent.

The calculations for this example were based on the assumptions that all units are started at the same time and construction for all units is completed. The utility could reduce its expected losses by cancelling units before completion and could reduce expected losses further by staggering the construction of its plants. Perhaps these two tactics could reduce Consolidated's expected loss from building four units by 50 percent, to $191 million. Consolidated would still choose to build no units. Staggered construction and abandoning plants during construction reduces Consolidated's expected losses from any given investment, but these tactics do not change Consolidated's decision to make no investment.

We can easily generalize this example. Under this regulatory environment, every positive investment has no chance to earn a profit and has some probability of showing a loss. With no possible upside gains and possible downside losses, all investments have a negative expected NPV and no utility will voluntarily make any long run investments. Utilities would be willing to make short run investments to alleviate power shortages once they occur, if the commission agrees that some investment is needed. However, short term investments generally produce power at higher marginal cost than long term investments.

Overinvestment penalties increase risk to stockholders and, therefore, raise the cost of capital. Suppose that the increased risk raises the cost of capital from 10 percent to 11 percent. Then a generating unit with construction costs of $62.735 million per year for 10 years adds $1.0489 billion to the rate base. The effect is to multiply each gain or loss and expected NPV in table 5-2 by 1.0489. If each unit is expected to last

exactly 30 years and then be costlessly scrapped, each unit costs users $.1206 billion per year for 30 years, an increase of 13.73 percent over the $.1061 billion per year each unit cost at a 10 percent cost of capital. (Of course, this increase in the cost of capital would be unimportant in a regulatory environment where no new investments are being made.)

Preventing Underinvestment

This analysis indicates that one consequence of strict application of the prudent investment test in an effort to protect ratepayers so that they have sufficient power at the lowest possible cost may be, under the operational-and-needed-investments-only rule, insufficient power at high cost. Commissions could try to correct this tendency to underinvest under this investment rule either by assessing penalties for underinvestment or by providing a gain, or real profit incentive, for utilities that invest the socially optimal amount.

Underinvestment Penalties

If actual demand turns out to be for five units and Consolidated only builds four units, regulators could impose a penalty. One penalty is to reexamine the utility's franchise to serve its current service area or to take certain other legal or regulatory actions. However, in keeping with the spirit of the financial analysis of this section, an appropriate response to underinvestment may be to impose a financial penalty--and for purposes of continuing the example we set aside here all questions regarding a commission's authority to impose such a penalty. In theory, if it is appropriately designed, the penalty for underinvestment would counterbalance exactly the incentive to underinvest. Carried to its logical conclusion, such a regulatory strategy would keep out of rate base an amount equal to the amount of underinvestment ($5 billion - $4 billion) and add to the rate base only Consolidated's actual investment less the underinvestment penalty ($4 billion - $1 billion = $3 billion).

Such a rule would mean that, if a utility with a $20 billion rate base refuses to invest an additional $4 billion to meet expected demand (because of overinvestment penalties), the commission might threaten to reduce the existing rate base to $16 billion. From this, the utility's interest coverage ratio would suffer, probably to the point where the utility would face bankruptcy.

Underinvestment penalties can also take the form of disallowed expenses, inadequate inflation adjustments, or reductions in the rate of return. We do not consider here the various other types of financial penalties except to note that, according to the Averch/Johnson rule, a reduction in the rate of return below the true cost of capital gives the utility a disincentive to produce power with an optimal capital cost/variable cost mix.[3] If an underinvestment penalty lowers the rate of return below the cost of capital, the utility would have a further incentive to underinvest.

Assume that the commission can require Consolidated to make some investment through threats of underinvestment penalties and assume that expected demand is still for 4.0 units (ignoring any effect of the penalty on marginal cost and hence demand). The expected NPV of building four units would be negative but, because of the penalty, other investments would have even lower NPVs. Therefore, Consolidated might be forced to build four units, the socially optimal investment. Imposition of both underinvestment and overinvestment penalties on the basis of prudence can then force a utility to make the socially optimal investment, but such a policy probably amounts to expropriation of the utility by the state because current shareholders lose money every time demand turns out to be different from the forecast value. A utility in this environment could not raise capital by selling stock except at prohibitively high dividend yields

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[3]See Harvey Averch and Leland L. Johnson, "Behavior of the Firm under Regulatory Restraint," American Economic Review 52 (December 1962a): 1052-1069; and F. M. Scherer, Industrial Market Structure and Economic Performance, 1st ed. (Chicago: Rand-McNally, 1970).

because new stockholders require immediate dividends to compensate them both for expected losses when demand turns out to be different from the forecast value and for increased risk.[4] This increased dividend yield has the effect of raising electricity costs and prices. High prices, in turn, dampen demand and reduce the optimal amount of investment.

This regulatory policy produces small amounts of power at very high prices. There are two categories of alternatives to this policy. One is to eliminate penalties and hence risk. The other is to provide an opportunity for increased profits to compensate for risk.

Profit Incentives

Suppose that a commission imposes overinvestment and underinvestment penalties, but also gives the utility some form of profit incentive. Ideally from the financial point of view, it would consist of both a lump sum increase in the rate base as compensation for expected losses and an increase in the rate of return as compensation for increased risk. In practice, without a change in statutes, such an increase in rate base could probably not be implemented directly; instead, commissions would want to grant an appropriate increase in rate of return that would yield the same resulting profit. However, the commission must grant the compensation for expected losses as a lump sum change in rate base and not as an increase in

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[4]Specific expected losses can be distinguished from increased risk. For example, assume that there is a 20 percent chance that firm C will be bankrupt 1 year from today, unable to pay either interest or principal on any bonds that it issues. If a risk neutral investor requires an expected 10 percent return, he would require a promised interest rate of 37.5 percent on 1-year discount bonds issued by firm C, with the extra 27.5 percent of promised interest being compensation for expected losses. (While a riskless bond has a zero standard deviation of returns, a 1-year discount bond issued by firm C has a 58 percent standard deviation of returns.) The typical investor is risk averse, not risk neutral, so he demands a higher than 10 percent expected return on a risky bond than on a riskless bond. Assume that he demands a 16 percent expected return on firm C bonds, in which case promised interest must be 45 percent. This 6 percent increase in expected return and the 7.5 percent increase in promised interest represent compensation for increased risk.

the rate of return. This is because an increase in the rate of return over the true cost of capital would again give the utility an incentive to produce power with a suboptimal capital cost/variable cost tradeoff. This incentive to overinvest, like the disincentive to invest discussed earlier, is also a result of the Averch/Johnson effect.[5] For purposes of simplicity in the example, however, we assume the "ideal" approach is possible.

Suppose that increased risk associated with penalties increases the cost of capital from 10 percent to 12 percent. A generating unit that costs $62.735 million per year for 10 years then adds $1.1009 billion to the rate base. If expected demand is still for four units, the NPV of building four units under the operational-and-needed-investments-only rule is -$.8404 billion. Then the lump sum compensation for expected losses must be +$.8404 billion also in order to make building four units a zero NPV project. If Consolidated builds four units and actual demand turns out to be for four units at a cost of $4.4037 billion, the commission would have to add $5.2441 billion to the rate base ($4.4037 billion + $.8404 billion). However, if demand turns out to be for three units or five units, the commission then adds $4.143 billion to the rate base (1.1009 x 3 + .8404), and so on. That is, the company includes in rates the construction costs of the units less penalties plus the compensation for expected losses.

If units last 30 years and are then costlessly scrapped, a $5.2441 billion increase in the rate base costs ratepayers $.6510 billion per year for 30 years. This is a 53 percent increase in amortized capital costs over the $.4243 billion in amortized capital costs with no penalties and a 10 percent cost of capital. These calculations were made assuming no change in demand, even though demand will necessarily decline in response to a 53.43 percent increase in amortized capital costs.

The commission can reduce the $.8404 billion rate base adjustment for expected losses by x percent if it reduces the penalties for overinvestment

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[5]See Averch and Johnson, "Behavior of the Firm"; and Scherer, Industrial Market Structure, pp. 529-537.

and underinvestment by x percent. The commission must make equal adjustments in the two penalties, however, because asymmetric penalties produce incentives to either overinvest or underinvest. For instance, a 100 percent penalty for overinvestment and a 0 percent penalty for underinvestment has already been shown to cause underinvestment (i.e., it causes no investment).

In the early 1980s, the Defense Department began using profit incentives for defense contractors, and Scherer advocates a similar use of profit incentives to encourage efficiency by public utilities.[6] It is an arguable point whether profit incentives for public utilities would increase efficiency enough to offset the increase in marginal cost that would occur because of the increased cost of capital.

Avoiding Poor Investment Incentives

There is a finite probability of management error in all corporations, including utilities. If commissions penalize these errors, for instance, by allowing only a part of the construction costs of a new unit to be added to the rate base, all investments have negative expected NPVs and no investments will be made. As we have seen, if the commission adds underinvestment penalties, unintended side effects can occur; for example, the cost of capital increases and the cost of electricity rises. There are at least three possible solutions to the problem of unintended side effects of penalties for mismanagement: contractor liability, insurance, and profit incentives.

For a sufficiently high increase in his bid, a contractor may be willing to accept liability for certain errors, such as some kinds of cost overruns. Here, we distinguish between two kinds of costs associated with cost overruns: controllable costs and uncontrollable costs. "Management mistakes" might be considered a controllable cost because a sufficiently competent and experienced management team could minimize these costs.

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[6]See "Procurement Success Story." Wall Street Journal 6 February 1984, p. 20; and Scherer, Industrial Market Structure, p. 537.

Retroactive safety regulations and delays caused by environmental litigation are examples of uncontrollable costs, costs that managers cannot control. The contractor probably would refuse to accept liability for uncontrollable costs such as retroactive safety regulations and delays due to environmental litigation. These extra costs are not due to management error. The effects of not allowing these costs to be added to the rate base are seen as perverse once it is realized that all investments would have negative expected NPVs. (Further discussion of the consequences of strict application of the prudence test on the utility-contractor relationship is presented toward the end of this chapter.)

For a price, insurance companies might accept some of the risk. Insurance companies accept liability for mistakes, even crimes, committed by bank employees, private detectives, tree surgeons, and workers in a host of other occupations. It might be possible for a board of directors to purchase a "mismanagement" insurance policy for a corporation. The relevant question then, of course, is whether ratepayers or stockholders should pay the insurance premium.[7]

A commission could compensate a utility for mismanagement risk by adding to the rate base a premium in addition to the cost of the actual investment, before any penalties. In the absence of competitive bidding, however, the commission would have extreme difficulty in determining a fair compensation for mismanagement risk.

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[7]Since the premiums would vary depending on the quality of the managers and the types of projects under construction, it might be more efficient to raise each manager's salary and require him or her to provide his/her own mismanagement insurance (the utility would be the beneficiary). This policy would be similar to situations where job applicants must be bonded (provide their own insurance) in order to be hired. However, it would result in extremely high salaries! If ratepayers must always somehow bear the risk of large investments being unneeded, either by bearing the cost of the investment or the cost of the insurance (or even the cost of high managerial salaries designed to cover mismanagment premiums), then poor investment incentives may be avoided. In such case, perhaps ratepayers should become equity owners. See Warren J. Samuels, "A Consumer View on Financing Nuclear Plant Abandonments," Public Utilities Fortnightly, January 10, 1985, p. 24, for an argument in favor of this view.

Summary of Investment Consequences

In order to build a power plant with a 10 or 12 year lead time, a utility must forecast demand 12 years into the future. If economic conditions change during the intervening 12 years, demand will probably turn out to be higher or lower than forecasted. Commissions may deny rate base treatment to utilities on the basis of prudence when demand turns out to be lower than forecasted by asserting that the plant, even though it was prudent ex-ante, is not prudent ex-post. Three different applications of an ex-post prudent investment rule to demand forecasting errors have been shown to have perverse unintended effects on the investment policies of regulated utilities. At least one regulatory environment, in theory, produces socially optimal investment, but a real world application might show that this environment also creates unintended consequences.

Our economic analyses of penalties did not distinguish the causes of risk; the results were identical for demand risk, management mistakes, and uncontrollable costs. Penalties reduce investment to zero; underinvestment penalties raise capital costs; combining penalties with compensation for penalty risk may increase efficiency, but not necessarily enough to compensate for increased capital costs. If all economists were asked to vote about whether it is "fair" to charge utility customers for unneeded power plants, management mistakes, and uncontrollable costs, the most votes would probably be cast for the proposition that charging for uncontrollable costs is fair, and the fewest votes would be cast for the proposition that charging for management mistakes is fair. Fairness, however, is not a factor that can be measured in an economic analysis.

Our three analyses indicate that strict application of a prudent investment rule to a utility for some type of undesirable behavior or outcome ought also to include a penalty for underinvestment and compensation to the stockholders both for expected losses and for increased risk. Even if these precautions are taken, any given application of a prudent

investment rule may still raise rates if the gain in efficiency does not fully compensate for increased capital costs due to increased risk.

The financial decision rule (NPV) used in this analysis was applied assuming that all types of generating units should be discounted at the same discount rate because the extra risk of the larger project is "diversifiable" and, therefore, not important to investors. However, the rule assumes no bankruptcy costs. As we know from the events of 1984, when a large nuclear unit has construction cost overruns, utilities may be threatened with bankruptcy. Therefore, projects with unproven technologies, uncertain costs, or requirements for great management skill that could threaten a utility with bankruptcy should be discounted at a higher project cost of capital than projects with proven technology.

Utility Bankruptcy

Utility bankruptcy is a possible consequence of applying the prudent investment test strictly so as either to disallow from rate base all or a part of a utility's investment in a completed electric utility plant or to disallow cost recovery for an abandoned plant in which a large investment has been made. Indeed major brokerage firms, such as Standard & Poor's, have openly discussed the possibility of utility bankruptcy. In a recent Standard & Poor's/Applied Economic Research Company Industry Survey (Utilities - Electric), the following appraisal was given about whether bankruptcy is possible in the electric utility industry:

> At least for the half of the industry currently involved in nuclear construction, the answer to this question is really who is going to bear the cost of the industry's nuclear nightmares: ratepayers or stockholders. How regulators will decide this issue realistically will be a matter of balancing ratepayer hostility against their judgement of utility management. Because the consequences of the regulator's decisions are more profound than any in current regulator's experience--the outcome could be anything from utility bankruptcies to electric rate increases markedly higher than even those during the energy crisis years--it is impossible

to foretell how the nuclear dilemma will be resolved. [Emphasis added.][8]

About half a dozen of the largest electric utilities are today on the brink of insolvency. One energy analyst at Goldman-Sachs has observed, "This is the closest utilities have come to bankruptcy in any time in our [recent] history...."[9] Yet, some critics dismiss the talk of bankruptcy as being a scare tactic, or as "a bluff or a negotiating ploy...[used] to force states to raise rates."[10] Nevertheless, the threat of utility bankruptcy has been taken seriously enough for the president of the National Association of Regulatory Utility Commissioners to request a meeting with the Secretary of Energy and the Vice President of the United States to discuss the role state regulators would play in the event of a utility bankruptcy.[11] Some consumer advocates have recommended bankruptcy as a solution to current problems, arguing that the advantages outweigh the disadvantages.

The following discussion is meant to summarize what is known and not known about the consequences of utility bankruptcy and the role of state regulators in that event.

The Consequences of Utility Bankruptcy for Investors and Customers

One recent study completed by the Congressional Research Service addresses the potential effects on rates of an electric utility bankruptcy.

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[8] Standard & Poor's Applied Economic Research Company Industry Survey (Utilities--Electric), March 1, 1984, as cited in Public Utilities Fortnightly, March 29, 1984, p. 40.

[9] "Generators of Bankruptcy: Some Utilities Are Approaching the Brink," Time, July 23, 1984, p. 81.

[10] Ibid., quoting Michael Totten, Director of the Critical Mass Energy Project.

[11] "NARUC Chief Seeks Meeting with White House to Discuss Bankruptcy Threat," Electric Utility Week, May 28, 1984, p. 2.

In that study, entitled Utility Bankruptcy: Thinking the Unthinkable, Kaufman and Dulchinos suggest that the possible consequences of utility bankruptcy might be analyzed by considering a hypothetical case study.[12] They assume a hypothetical utility that (1) has the capital structure shown in table 5-3, (2) has $2.5 billion invested in the construction of a new plant, of which it is sole owner, (3) has funded the construction by short term construction loans, and (4) is allowed to accumulate AFUDC of $0.5 billion, but is not allowed construction work in progress (CWIP) in the rate base. They then assume that the construction of the new plant is halted and the plant is abandoned, with a salvage value of $500 million.

Kaufman and Dulchinos limit their analysis to a consideration of the increased costs resulting from changes in the cost of capital brought about by bankruptcy. They do not consider tax effects or the relative merits of allowing CWIP in the rate base over the use of AFUDC.

TABLE 5-3

INITIAL CAPITAL STRUCTURE OF A HYPOTHETICAL UTILITY

Component of Capital Structure	Book Value ($ in millions)	Percentage of Total Capital Structure	Component Cost of Capital	Weighted Cost of Capital
Debt	$1,300	43%	10%	4.3%
Preferred Stock	300	10	8	0.8
Equity	1,400	47	14	6.6
Total	$3,000	100		11.7
CWIP	$2,500			
Revenues Required to Achieve Authorized Return	$ 351			

Source: Alvin Kaufman and Donald Dulchinos, Utility Bankruptcy: Thinking the Unthinkable, Report No. 84-95 S (Washington, D.C.: Congressional Research Service, Library of Congress, 1984), p. 16.

[12] Alvin Kaufman and Donald Dulchinos, Utility Bankruptcy: Thinking the Unthinkable, Report No. 84-95 S (Washington, D.C.: Congressional Research Service, Library of Congress, 1984), pp. 15-21.

First, Kaufman and Dulchinos assume that state regulators allow the utility to recover the direct construction costs of $2 billion over a period of time, but not the accumulated AFUDC. They then assume that the hypothetical utility converts its short term construction debt to long term notes and bonds covering the cost recovery period, at the current rate of 14 percent, resulting in the capital structure shown in table 5-4. Customers then pay an additional $279 million in rates to cover the cost of this debt. According to Kaufman and Dulchinos, this first case would imply an average annual increase of $235 for residential customers of the hypothetical utility.

TABLE 5-4

NO BANKRUPTCY CASE: CAPITAL STRUCTURE OF THE HYPOTHETICAL UTILITY

Component of Capital Structure	Book Value ($ in millions)	Percentage of Total Capital Structure	Component Cost of Capital	Weighted Cost of Capital
Old Debt	$1,300	26%	10%	2.6%
New Debt	2,000	40	14	5.6
Preferred Stock	300	6	8	0.5
Equity	1,400	28	14	3.9
Total	$5,000	100		12.6
Revenue Required to Achieve Authorized Return	$ 630			

Source: Alvin Kaufman and Donald Dulchinos, Utility Bankruptcy: Thinking the Unthinkable, Report No. 84-95 S (Washington, D.C.: Congressional Research Service, Library of Congress, 1984), p. 16.

Then, Kaufman and Dulchinos assume that (1) the state commission refuses to allow recovery of the costs of the abandoned plant in rates, (2) the utility becomes insolvent, defaulting on its debt payments, and (3) the utility goes into a Chapter 11 reorganization (a form of bankruptcy), either voluntarily or involuntarily. In such a case, the existing debt becomes due and payable, and interest rates of certain incentive agreements rise to current levels, assumed to be 14 percent as shown in table 5-5.

TABLE 5-5

BANKRUPTCY CASE: CAPITAL STRUCTURE OF THE HYPOTHETICAL UTILITY

Component of Capital Structure	Book Value ($ in millions)	Percentage of Total Capital Structure	Component Cost of Capital	Weighted Cost of Capital
Old Debt	$1,300	26%	14%	3.6%
New Debt	2,000	40	18	7.2
Preferred Stock	300	6	8	0.5
Equity	1,400	28	17	4.8
Total	$5,000	100		16.1
Revenue Required to Achieve Authorized Return	$ 805			

Source: Alvin Kaufman and Donald Dulchinos, Utility Bankruptcy: Thinking the Unthinkable, Report No. 84-95 S (Washington, D.C.: Congressional Research Service, Library of Congress, 1984), p. 16.

New debt is acquired to replace the short term debt, but has a substantial risk premium, costing 18 percent. The required return on equity is assumed to increase from 14 percent to 17 percent. Because of the increased cost of capital, the annual revenue requirement increases by $454 million over the base case. According to Kaufman and Dulchinos, an average annual rate increase of $382 is then required for residential customers of the hypothetical utility. However, if shareholders earn no return on equity, the residential customer of the hypothetical utility would see virtually no increase in rates.

Kaufman and Dulchinos recognize that the results of their hypothetical example are sensitive to changes in the assumed interest rate and the debt load, and that the hypothetical example is simplistic in that most state commissions amortize the construction cost of abandoned plant over a period of years. Also, there are tax effects that have not been incorporated, and a portion of debt is likely to be written off or restructured in bankruptcy. Yet, the point made is that bankruptcy may result in an increase in the cost of capital that could well require a larger increase in utility rates than that required without bankruptcy.

The Consequences of Bankruptcy for State Regulators

This subsection addresses the role of state regulators in a debt reorganization proceeding under Chapter 11 of the bankruptcy law. In law, two types of corporate bankruptcy are possible: debt reorganization and liquidation. It should be emphasized that the only possibility considered here for an insolvent utility to continue operating is a debt reorganization under Chapter 11 of the bankruptcy laws. A Chapter 7 liquidation would consist of a sale of assets that would probably result in a discontinuance of service by that utility. Hence, debt reorganization is considered the more likely alternative in bankruptcy. However, it might be possible for a neighboring (or another) utility to provide service to customers if it were to purchase the liquidated assets and immediately obtain a certificate of convenience from the state commission having jurisdiction over the sales.[13]

The role that state regulators would play in the event of a utility bankruptcy is uncertain because no utility has filed for debt reorganization under Chapter 11 of the bankruptcy law in several decades. Moreover, the recently enacted Bankruptcy Reform Act of 1978 contains major changes in both substantive and procedural bankruptcy law, which have been applied only recently to transportation utility bankruptcy proceedings.

Kaufman and Dulchinos observe that there were two major transportation utility cases in which the new bankruptcy law was applied. Both involve the airline industry. After the airline industry was deregulated in 1978, new entrants came into the industry and competed for customers against more established carriers by reducing fares on the more heavily travelled routes. Many of the airlines borrowed heavily to finance rapid expansion. During the same period, operating costs and interest rates increased, while the number of people flying declined during the 1980-82 recession. The

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[13]See Alvin Kaufman et al., Unplanned Electric Shutdowns: Allocating the Burden (Columbus: The National Regulatory Research Institute, 1980), pp. 63-68.

resulting negative cash flows caused Braniff and Continental airlines to file for debt reorganization under Chapter 11 of the bankruptcy laws in Spring 1983 and Autumn 1984, respectively.[14]

The effects of the Chapter 11 debt reorganization were different for the two airlines. While Braniff Airlines was closed for nearly 2 years after filing its Chapter 11 petition, Continental Airlines was back in operation within a few days. Both airlines eliminated some routes when they resumed service, and other airlines offered expanded service on many of those routes. Customers holding tickets at the time that Braniff filed for bankruptcy were provided service by other airlines, which were later reimbursed under existing default agreements among the airlines.

In both cases service to customers was maintained, even though some customers suffered a temporary inconvenience.[15] It is worth noting that Chapter 11 debt reorganizations of these airlines were processed under Subchapters 1 through 3 of Chapter 11 of the current bankruptcy law, which makes no mention of protecting "the public interest."

Subchapter 4 of the bankruptcy act, which deals solely with railroad reorganization and does mention the public interest, was not used for the airlines.[16] One can make a compelling argument that, in the case of an electric utility, there is a public interest in the continuation of service, just as there is a public interest in continuing rail service.[17]

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[14]Kaufman and Dulchinos, Utility Bankruptcy, pp. 8-13.

[15]Ibid.

[16]See Bankruptcy Reform Act of 1978, section 103, 11 USC § 103 (as amended 1978). Also see Sen. Rep. No. 95-989, 9th Cong., 2nd Sess. 133 (1978), which states that railroad reorganizations are a special case because of the public need for continuous service.

[17]For a fuller elaboration of this argument, see the Honorable Rosemary S. Pooler, "Legal Issues Confronting Regulation in the Event of Bankruptcies," a paper presented to the NARUC Technical Education Conference for Commissioners (San Diego, July 23, 1984).

This argument is even more persuasive when one considers that it is likely that the special provisions to protect the public interest in the case of a railroad reorganization probably found their origin in the United States Supreme Court case of Palmer v. Massachusetts, which held that the trustees for a bankrupt railroad could not abandon certain local passenger services over the objections of the state commission.[18] Considering that maintenance of adequate service is mandated under a utility's obligation to serve, by both state and federal regulatory commissions, the trustee in bankruptcy in a gas or electric utility reorganization is likely to continue to operate the utility.[19] In other words, it is unlikely that customer service would be discontinued in the event of a Chapter 11 debt reorganization.

The potential role of a state regulator in a utility debt reorganization under Chapter 11 is provided for in section 1129(a)(6) of the Bankruptcy Reform Act of 1978. Section 1129 generally concerns the confirmation of the debt reorganization plan, which actually occurs late in the debt reorganization process. Before this occurs, the court appoints creditors' and equity security holders' committees;[20] the court (on the request of a party in interest) appoints a trustee or examiner;[21] the debt reorganization plan is developed, either by the debtor or by a party in interest;[22] and each class of claims or of interests (as set forth in the reorganization plan) must accept the plan.[23] At that point, assuming

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[18]Palmer v. Massachusetts, 308 U.S. 79 (1939).

[19]See Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 388 (1959) for an example of the line of United States Supreme Court cases holding that a utility has an obligation to maintain adequate service in the public interest.

[20]Bankruptcy Reform Act of 1978, Section 1102, 11 U.S.C. §1102.

[21]Bankruptcy Reform Act of 1978, Section 1104, 11 U.S.C. §1104.

[22]Bankruptcy Reform Act of 1978, Section 1121, 11 U.S.C. §1121.

[23]Bankruptcy Reform Act of 1978, Section 1126, 11 U.S.C. §1126.

that the plan has not been modified by its proponent,[24] the court holds a confirmation hearing.[25] At no point prior to the confirmation hearing is there any explicit provision in the new bankruptcy act for a state commission to have a role. Moreover, it is somewhat doubtful whether a state commission would have any standing to be heard in the bankruptcy case because it is not clearly a party in interest in the bankruptcy.[26]

Section 1129(a)(6) provides that the bankruptcy court may confirm a reorganization plan only if

> [a]ny regulatory commission with jurisdiction, after confirmation of the plan, over the rates of the debtor has approved any rate change provided for in the plan, or such rate change is expressly conditioned on such approval.[27]

Thus, no reorganization plan proposed by any party in interest (including the debtor, the trustee, a creditors' or equity security holders' committee, a creditor, an equity security holder, or any indenture trustee) will be confirmed unless the regulatory commission that will have jurisdiction over the debtor after the confirmation of the plan has approved the rate change provided for in the plan. As an alternative, the rate change may be

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[24]Bankruptcy Reform Act of 1978, Section 1127, 11 U.S.C. §1127.

[25]Bankruptcy Reform Act of 1978, Section 1128, 11 U.S.C. §1128.

[26]The Bankruptcy Reform Acts provides that "[a] party in interest, including the debtor, the trustee, a creditor's committee, an equity holders' committee, a creditor, an equity security holder, or any indenture trustee, may raise and may appear and be heard on any issue in a case under this chapter." Bankruptcy Reform Act of 1978 §1109(b), 11 U.S.C. §1109. Because the list of parties in interest only includes the debtor, the creditors, the equity and bond holders of their representatives, an argument might be made that a state commission is not a party in interest. Also see, in re Devonian Mineral Spring Co., 272, F. 527, 532 (D.C. Ohio,), which uses a "pecuniary interest" test to define party in interest.

[27]Bankruptcy Reform Act of 1978, Section 1129 (a)(6), 11 U.S.C. §1129.

conditioned on such approval.[28] No provision, however, is made to allow a state commission to object to the reorganization plan.[29]

The precise wording of section 1129(a)(6) has several implications. First, it might be possible for a reorganization plan to be confirmed if the rate change is expressly conditioned on the approval of the regulatory commission with jurisdiction after confirmation of the plan. A state commission might then be faced with a tough decision about whether to approve a rate increase provided for in a utility debt reorganization plan. The commission might find it difficult to deny the rate increase because the increase would probably be necessary "to effectuate substantial consummation of [the] confirmed plan."[30] If the commission denies the rate increase and if the increase is necessary to effectuate the confirmed plan, the court would have the option of converting the debt reorganization under Chapter 11 into a utility liquidation under Chapter 7.[31] In effect, the commission could be faced with either granting the rate increase or seeing the assets of the utility liquidated.

Indeed, one prominent financial attorney, Jacob Worenklein, recently noted that a bankruptcy court can pressure state commissions to raise rates

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[28]S. Rep. No. 95-989, 9th Cong., 2nd Sess. 126 (1978).

[29]See Bankruptcy Reform Act of 1978, §1128 (b), 11 U.S.C. §1128, which states that "[a] party in interest may object to confirmation of a plan." The term "parties in interest" includes not only general creditors, but prior and several creditors as well, and also the bankrupt and every other party, whose pecuniary interest is affected by the proceedings. In re Devonian Mineral Springs, Co., 252 F. 527-532 (D.C. Ohio,). Cf., the Bankruptcy Reform Act of 1978, section 1164, 11 U.S.C. §1164, which expressly provides that "any State or local commission having regulatory jurisdiction over the debtor [railroad] may raise, may appear and be heard on any issue in a case.., but may not appeal from any judgment, order, or decree entered in the case." But as noted earlier, §103 (g) of the Bankruptcy Reform Act of 1978, makes it clear that subchapter IV of Chapter 11 applies only to railroad reorganizations.

[30]Bankruptcy Reform Act of 1978, section 1112 (b)(7) 11 U.S.C. §1112.

[31]Bankruptcy Reform Act of 1978, section 1112 (b), 11 U.S.C. §1112.

before it confirms the utility's reorganization plan. It is unlikely the bankruptcy court would confirm a reorganization plan without adequate rate relief, according to Worenklein. If a refusal of rate relief kept the court from confirming the reorganization plan, keeping the utility in Chapter 11, this could cause legal and financial complications that would threaten reliable service.[32]

It is worth noting that the provisions of section 1129(a)(6) specify that the reorganization plan will be confirmed provided the regulatory commission with jurisdiction over the rates of the utility after confirmation of the plan approves the rate changes (presumably rate increases) provided for in the plan. Thus, the provisions of section 1129(a)(b) do not necessarily require the approval of the rates by a state regulatory commission if the utility debt reorganization plan provides for a transfer from state to federal jurisdiction. Such a transfer of jurisdiction might occur if the reorganization plan provides for a spinning off of the utility's distribution facilities and creation of a generation and transmission entity. Furthermore, it is likely that the bankruptcy court could--if it chose to--execute a confirmed reorganization plan without state commission approval, transferring regulatory authority over a newly created generation and transmission facility to federal jurisdiction.[33] All the sales made by the new generation and transmission entity would then be on the wholesale level and regulated by the Federal Energy Regulatory Commission (FERC). If the FERC were willing to approve the rate increase provided for in the confirmation plan or the FERC had more favorable regulatory policies (such as providing for CWIP in rate base) than the state commission, then the utility might seek a shifting of jurisdictions in its reorganization plan. While the distribution entity would still be regulated by the state commission, there has been some suggestion that the state commission would

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[32]See "Utility in Chapter 11 Still Must Answer to States on Rates, Lawyer Says," Electric Utility Week, June 11, 1984, p. 11.

[33]See generally Bankruptcy Reform Act of 1978 section 1142, 11 U.S.C. §1142.

be required to pass through automatically the wholesale power rates approved by the FERC.[34] State regulators would then be left with direct regulatory authority over the local distribution company stripped of its generation and transmission facilities. If so, a utility reorganization plan could be written so as to limit the role of state regulators in determining the rates faced by ultimate customers.[35].

The studies of potential effects of bankruptcy reported above have, for the most part, emphasized the undesirability of utility bankruptcy from the state commission point of view. As demonstrated by Kaufman and Dulchinos, utility bankruptcy could lead to an increase in the cost of capital, which would in turn lead to increased rates.[36] Chapter 11 debt reorganization might result in a state commission being faced with the undesirable choice of either granting a rate increase or forcing a utility into liquidation, with the attendant uncertainties regarding continuation of service. A Chapter 11 debt reorganization might conceivably lead to a loss of commission jurisdiction over a generation and transmission entity that might be created by the debt reorganization plan.

Still, most state regulatory commissions possess broad powers to regulate financial and other corporate matters. For example, approval by the state commission is usually required prior to the purchase or sale of facilities, the issuance of securities, purchase of securities of other utilities, issuance of restricted stock options, and entrance into lease

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[34]See generally, Thomas Pietrantonio, "The Preemptory Effect of an FERC Rate Approval," Public Utilities Fortnightly, August 16, 1984, pp. 54-48, for a discussion of the conflict between the "Narragansett Doctrine" and the Pike County Light & Power cases.

[35]For a discussion of the issues that would arise should a public utility holding company or its subsidiary file a petition for a Chapter 11 reorganization, see Pooler, pp. 7-10.

[36]Kaufman and Dulchinos, Utility Bankruptcy.

transactions. Prior approval by the state commission is also usually required for a merger or consolidation.[37] Several commissions even participate as a party in corporate reorganization proceedings.[38] While their powers do not permit state commissions to release utilities from debts, the broad regulatory powers that they possess over the finances and corporate structure of regulated public utilities tend to approximate many of the powers available to a bankruptcy court. In other words, with the exception of release from a utility's debt, there is little available under the Chapter 11 bankruptcy proceedings that cannot be achieved under the state commission.[39]

Why then would a state commission, either by action or inaction, allow a utility to become insolvent? What can be gained from bankrupcty?

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[37]Geneva Beirerlein, ed., 1982 Annual Report on Utility and Carrier Regulation of the National Association of Regulatory Utility Commissioners (Washington, D.C.: NARUC, 1983), pp. 525-528.

[38]Ibid., p. 526-528. Specifically, the following state commissions participate as a party in a corporate reorganization proceeding: the Arkansas Public Service Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Indiana Public Service Commission, Louisiana Public Service Commission, Michigan Public Service Commission, the North Dakota Public Service Commission, the Oregon Public Utility Commissioner, the Pennsylvania Public Utility Commission, the Rhode Island Public Utilities Commission, and the Vermont Public Service Board. In addition, the New Hampshire Public Utilities Commission participates as a party in corporate reorganization proceedings to the extent that approval is required; the New Jersey Board of Public Utilities participates as a party at staff discretion; the Washington Utilities and Transportation Commission participates as a party if securities are to be issued; and the Public Utilities Commission of Ohio sometimes participates as a party, depending on the transaction. The New York Public Service Commission requires its approval of corporate reorganizations.

[39]Conversations with Aaron Levy of the Securities and Exchange Commission at the NARUC Staff Subcommittee on Law meeting, Madison, Wisconsin, June 6, 1984. See also Alvin Kaufman et al., Unplanned Electric Shutdowns, p. 67. Further, Kaufman and Dulchinos suggested that because most regulatory bodies already have many of the powers of a bankruptcy court, a utility bankruptcy can be considered a regulatory failure. See Kaufman and Dulchinos, Utility Bankruptcy, p. viii.

Regulators might allow a regulated utility to become insolvent, making it a candidate for bankruptcy, if it made a large investment that is not used and useful and will not become used and useful in the near future. Only then could a refusal of the rate increases necessary to allow the utility to continue to operate be considered to be in the best interest of the ratepayers (as well as be nonconfiscatory.)

Even then the state regulatory agency might need to take a more active role in a Chapter 11 debt reorganization than that expressly provided for in the Bankruptcy Reform Act of 1978. State regulators would need to seek standing as a party in interest in the debt reorganization.[40] Then, state regulators would be in a position to advocate that either (1) portions of the utility's debt be written off rather than converted to new debt at current interest rates, (2) the debt be restructured so as to tie the repayment to future earnings, or (3) the generating plant of the utility that is identified as not being used or useful be sold to utilities in the region with capacity shortages either now or projected in the near future.[41] The primary objective of state regulators, as opposed to that of the court and most other parties, would be to see that the utility's ratepayers receive electricity at the lowest reasonable cost, consistent with reliable, adequate service. Even with this objective in mind, state regulators might wish to reconsider carefully their actions or inactions before taking any steps that might force a utility into bankruptcy because of the indirect effects that a utility bankruptcy might have in the financial markets. Other utilities (particularly those utilities in financial difficulties and those in the same jurisdiction as the candidate bankrupt utility) might see their costs of capital rise to offset the higher risks perceived by investors. This too would eventually lead to higher rates.[42]

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[40]This suggestion might require statutory changes in the Bankruptcy Reform Act of 1978.

[41]Kaufman and Dulchinos, Utility Bankruptcy, p. 21.

[42]Ibid., p. 20.

Utility Relationships

Between the extreme consequences of a utility risking bankruptcy by undertaking construction and a utility refusing to undertake construction for fear of bankruptcy are many other, less severe, possible consequences of frequent, strict prudence applications. These represent shifting relationships among the parties with an interest in utility construction as they adjust to a possibly new regulatory environment.

The consequence of these shifting relationships is usually to increase costs in ways that ultimately are borne by utility customers. While these cost increases are important, they are all difficult to quantify. Hence, it is not possible to forecast the net effect on rates of protecting customers from imprudently incurred costs, forcing managers and other parties to be more efficient, and increasing costs because of shifting relationships.

Capital Costs

Frequent and severe application of the prudent investment test would affect utility relationships with the financial community and--even without a bankruptcy--would result in higher costs of capital. Bond rating agencies and the stock market take account of a utility's ability to have all of its capital expenditures recognized by its regulatory authorities and included in the rate base. If exclusion becomes common, a certain consequence is to increase the cost of raising capital, both debt and equity, in the financial markets. As the cost of money increases, so does the cost of financing construction and the cost to the ratepayer of providing a return on investments that enter rate base.

This consequence is, perhaps, to be expected in a period of higher utility risk, as discussed in the previous chapter. Investors, as risk-takers, may assume more risk but require a high return.

Utility-Contractor Relations

To date, most relationships between utility officials and equipment vendors, architect-engineers, and construction firms have been one of partnership in construction. A possible consequence of regular prudence investigations may be to move utilities into a more "arm's length" relationship with contractors, possibly one characterized by mutual mistrust and suspicion. If heavy pressure on utilities to question every activity of a contractor becomes the norm, the mutual trust and confidence between the parties and their treatment of each other as partners in a construction endeavor may be impaired, if not lost.

The utility should and must insist that it gets all it contracts for and pays for. But, a team atmosphere and a cooperative spirit are essential in undertaking a major project, and these can be weakened by the tension and apprehension of an "arm's length" relationship.

Such a posture is not all bad, of course. There are numerous occasions where a utility may ask the contractor to perform tasks that the contractor regards as unnecessary, wrong, or even foolish. Under the relationship to date, the contractor may agree to perform the tasks to preserve good relations. Under the likelihood of a prudence investigation, the contractor will be compelled to disagree and to do so in writing for his own protection.

However, if this mode of behavior is taken to extremes, it may become very difficult for the utility to function effectively with its contractors.

Bidding Policies

Until now, most major contractors have bid on utility projects on the basis of cost plus a reasonable fee. It was generally argued that this resulted in the utility obtaining the lowest cost. The alternative of a

"fixed-price," lump sum bid requires the contractor to include a large provision for contingencies.

Under the cost-plus contract, however, contractors are unable to make provisions for the possibly large costs of their involvement in a prudence investigation, or resulting litigation, following construction. To protect themselves, contractors on relatively small utility undertakings will build into their bid proposals adequate protection against the potential liabilities they could incur if utilities seek compensation from their contractors on costs that have been disallowed on the basis of a prudence inquiry.

Lump sum bidding may then have to become the norm, possibly resulting in higher costs for the same services and equipment. For large contracts involving millions or even billions of dollars, the only contractors who might risk lump sum bids are those with only limited assets to protect. Their solution to a major repayment obligation could be to declare bankruptcy. The large established architect-engineering firms could well withdraw from bidding--to no one's long term advantage.

Moreover, insurance rates are reported to have risen very sharply for such firms, and other firms are reportedly experiencing difficulty in obtaining insurance because of concern over prudence questions. Rising insurance rates can add to the cost the ratepayer must bear.

Increased Litigation

If state commissions disallow certain expenses on grounds that utility management or its contractors did not act prudently, increased litigation is a probable consequence. Indeed, a commission might require a utility to recover all possible costs by litigation before deciding how the residual costs are to be treated. Where utility management has been found by the state commission to have been imprudent, stockholder derivative suits will almost certainly result.

Of course, commissions should not hesitate to act properly just because litigation, including stockholder suits against management, might result. What is worth considering, however, is the possible long term cost consequences of such a situation. An analogous situation may be the estimated $15 billion added yearly to medical costs in the U.S. by malpractice cases. These have increased from five per one hundred doctors in 1975 to sixteen per one hundred doctors in 1983.

Utility boards of directors should be held responsible for the actions of the managers they have selected. In some cases they have changed management because of overruns and inefficiencies leading to delays and much higher costs. The prudent investment test may play an important role in assuring that such utility directors responsibly discharge their duties. Increased litigation to bring this about may increase costs in the short to medium term. The long term effect on costs could be higher because of litigation or lower because of greater managerial efficiency.

Record Keeping

Another possible consequence is an increase in the expenses associated with the records that the various parties must keep. All business activities ought to be reasonably well documented, especially those dealing with major and complex contracts. If, however, the prudence test is applied with increasing strictness by state commissions, the consequence may be far greater and more detailed record keeping by both utilities and contractors. Much of this will be unnecessary for engineering purposes and will add to the cost of any facility being constructed. Insofar as nuclear facilities are concerned, the NRC already requires extensive and expensive record keeping.

This may increase to a level where, as in the field of medicine, contractors, like doctors practice "defensive medicine." This means that they routinely order all sorts of tests, many of which may be irrelevant and expensive, just to have a battery of results available for the

malpractice suit. The doctors, of course, do not pay for them--the patients or their insurance companies do, increasing the cost of medical care.

The point here is not that careful records should not be kept. Certainly, the questions a regulatory body or its staff wishes to explore should not be dismissed with the simple observation that there are no records. Rather, it is that a prudence investigation well after the fact may force utilities and contractors to shift into a more burdensome type of record keeping, much of which is very likely to be self-serving to protect against a possible lawsuit.

Technical Innovation

Strict application of the prudent investment test could ensure that utilities seek out the best means of meeting the needs of the customers. Some economists believe that reducing risk for utilities has a perverse side effect, namely, it produces a reluctance to adopt new technology. This, in turn, may be costly to society because the rate of progress slows.

However, even if this were true, no commission can solve this problem by itself, because of the "free-rider" problem: requiring a utility to take on the risks of a new technology forces its consumers to bear the financial risk of the new technology. Once the new technology proves successful, other commissions can authorize use of the now proven technology and obtain its benefits for their consumers without exposing them to any of the risk.

On the other hand, commissions may unintentionally lead utilities to use new technology. Suppose that a utility considers building three 400-megawatt nuclear plants with proven technology and or one 1,200-megawatt plant with unproven technology and expected 12 percent economies of scale. Capacity planning models usually apply the same discount factor to both proposals and show the 1,200-megawatt plant to be 12 percent cheaper than

the three 400-megawatt plants. A regulator might then require the utility to choose the 1,200-megawatt plant with unproven technology.

Further, architect-engineers and equipment manufacturers have played major roles in putting and keeping the United States in the forefront of technological development in the field of electrical design and construction. A possibly stifling effect on new designs could result if they had to defend all efforts at improving equipment, systems, and construction technology to regulatory agencies, and perhaps the courts.

CHAPTER 6

FUTURE DIRECTIONS FOR THE PRUDENCE TEST

In this final chapter, we consider issues relating to the concept of prudence in public utility regulation that need to be resolved. Most of these issues will be resolved only in future applications of the concept by state and federal commissions and perhaps by judicial review of commission decisions. To conclude the chapter, we present our commentary of how some of these issues are likely to be decided. To begin, we summarize what we have said in the first five chapters about the current legal status of the prudent investment test.

Current Legal Status

The concept of prudence as it applies to public utilities has been judicially developed. It is not a hard and fast rule of law, but a concept that is in some respects vague and still evolving. The term "prudence" describes a tool available to regulators. Although it is not well articulated, it is used, and its application is referred to as the prudent investment test.

The use of prudence in utility law has direct antecedents in other areas of law where the concept continues to be used as a method of providing managerial oversight. Two principal areas--trust law and oil and gas law--provide important analogous case law that is instructive in the use of prudence in public utility law.

The United States Supreme Court has not given an explicit majority approval to the use of the prudent investment test, even as a method of valuation to determine the value of plant to go into rate base. Rather, the Court has adopted an end-result test, expressed in Hope Natural Gas, as its constitutional standard.[1] This end-result test looks not to the

[1]Federal Power Commission v. Hope Natural Gas Co, 320 U.S. 591 (1944).

method or theory used in rate base valuation, but rather looks to the total effect of the end result of a rate order. If the end result is not unjust and unreasonable and does not result in confiscation, then the valuation method or theory will be upheld.

It appears that there are only a few instances where the prudence concept has been imposed as a statutory standard in public utility law. The Federal Power Act does not use the term. The Natural Gas Act and the Natural Gas Policy Act of 1978 do not use the term, although legislation is currently pending to amend the latter by including prudence as a standard governing natural gas acquisition. Most state utility statutes do not appear to use the term; although where it has been used in statutes, its meaning and usage have usually incorporated much of the judicially developed definition.

One decision apparently interpreting a state statutory provision is Northwestern Bell Telephone Co. v. State,[2] which held that the words "prudent acquisition," for the purpose of a statute allowing such an acquisition to be included in a telephone company's rate base, are not words of art referring only to a decision by one utility to acquire property belonging to another successor utility, but are also words applying to decisions regarding expenditures of every kind made by the utility.

Until recently, the prudent investment concept was treated for the most part in an almost perfunctory manner, as state regulators relied on the presumption of prudence in considering utility decisions. The frequent application of the prudent investment concept as a test to judge utility decisions involving construction cost overruns and plant additions and cancellations is relatively recent. Thus, while it is generally thought that the prudent investment test is a well-established standard in public utility regulation, it is not. Rather it is of more recent development as now applied. However, one can argue that the current stricter use of

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[2]Northwestern Bell Telephone Co. v. State, 216 N.W.2d 841,852, 299 Minn. 1 (1947).

prudence is the way that the law always would have been interpreted if today's riskier circumstances had arisen before.

The procedures for using the test are, in some ways, still not well defined. We know only that certain guidelines have been held as necessary for commissions to follow in order to have a prudent investment test application sustained by the courts. These four guidelines, which are explained in chapter 3, require (1) a rebuttal of the presumption of prudence, (2) a rule of reasonableness under the circumstances, (3) a proscription against hindsight, and (4) a retrospective, factual inquiry. But following these four guidelines does not necessarily place an application of the prudent investment test on solid ground with respect to judicial review because the legal weight of the test measured against other legal requirements is uncertain. Further, successful application of the concept in a specific case is uncertain because there is no specific, universally accepted checklist of what constitutes a prudent investment decision.

In practice, state commissions tend to move quickly to determining the facts of the particular case, without extensive articulation of the nature of the concept of prudence or of its procedural application. The prudent investment test as currently used in public utility regulation is an important but imprecise standard against which regulators judge the investment decisions of utility managers. Nevertheless, the concept of prudence is legally available--certainly for reviewing current and future utility decisions, and perhaps in a more limited way for reviewing the decisions of the past.

While useful parallels can be drawn between the concept of prudence in public utility law and the prudence concept in analogous areas of law, many issues concerning prudence and its application are as yet unresolved in the public utility law: What is it? Toward what is it evolving? How useful is it? How can it be better articulated? To some extent, those who refer to the prudence test in its current role as a long-standing regulatory

principle are characterizing the concept as something that it is not. As a result, there is a danger of misapplication of the concept in the hearing room where the legal concept often merges with its policy application.

In the two sections that follow, we first consider issues to be resolved in future applications of the prudent investment test. Then, we present our concluding analysis regarding future directions for the prudent investment test and our views on some of these issues.

Issues To Be Resolved

One set of issues relates to articulating more fully both the nature of a prudent investment decision in the utility business and the regulatory procedures for judging the prudence of a utility decison. Debates over prudence have prompted some spokesmen, both for regulators and for utilities, to call for greater commission involvement in regulated company investment planning. A second set of issues concerns the appropriateness of such involvement. Also, as discussed in the previous chapter, concerns over the consequences of strict application of the concept of prudence to large capital investment decisions raise a set of issues relating to appropriate limitations in applying the prudent investment test. These three sets of issues are taken up next.

Nature and Use of the Prudence Test

While several state commissions have recently used the prudent investment test extensively, the substantive and procedural elements of the standard are not yet well articulated. State commissions in applying the test have concentrated more on setting out the facts of specific cases than on the elements of a prudent decision or on the procedural elements of a prudence inquiry. What still needs to be developed is a well-established process for determining what constitutes a prudent decision for utility managers.

While many agree that the substantive elements of prudence need to be further articulated, there is no ready agreement about what this means. To some, it means establishing for each type of case (cost overruns, abandonment, and so on) what is a prudent or imprudent decision under various circumstances. The problem is that this may amount to issuing a "guidebook" to utilities for each type of decision they must make. Such a utility "guidebook" will not necessarily result in the avoidance of imprudent decisions--only good decision making will. To others, articulating the elements of prudence means simply introducing into the regulatory inquiry some clear standard of prudence that is generally applicable.

Further, it is necessary to develop and articulate the regulatory procedures for looking at prudence. This could be accomplished by means of state regulators announcing the general procedural elements of the prudence test in any case where it is used. Alternatively, it might best be accomplished by a gradual case-by-case development of procedure. Of course, the procedural elements of the prudent investment test could be articulated by state legislation. However, this would tend to remove from the procedures the flexibility and discretion that regulators might find desirable as the test evolves in regulatory law.

Articulation of the prudent investment test process may be necessary in order to assure deference by state and federal courts to state commissions in cases involving application of the prudent investment test. Courts normally give judicial deference to the quasi-judicial processes of administrative agencies such as the state commissions. However, in order to assure judicial deference in state applications of the prudent investment test, the procedure for the test should be spelled out; otherwise, a court might find the commissions' decisions to be arbitrary and capricious, and hence unlawful, either under the applicable state administrative procedures act or as a matter of due process.

Perhaps the most significant issue to be resolved about the nature of the prudent investment test is how it relates to the used-and-useful test.

In one view, the prudent investment test and the used-and-useful test are two distinct tests. Viewed another way, the prudent investment test and the used-and-useful test are actually two statements of the same valuation standard.

If the tests are distinct, an important issue is whether rate base treatment requires an investment to be both prudently decided and used and useful, or just either one of these. Some analysts have suggested that only one of the two tests need be applied in a rate base determination. This, of course, raises the question of which test should be chosen, since the outcome will depend heavily on the test. Some utility representatives have asserted that it is unfortunate that all state utility statutes have a used-and-useful test because it confuses the real issue of whether utility management has acted prudently. In certain recent excess capacity cases, electric utilities have admitted that some generating capacity is (at least temporarily) not useful, but they have argued for rate base treatment of that capacity on the basis of the prudence of the decisions that led to excess capacity. Commissions in some cases have agreed with this argument.

In some other cases, the language in commission opinions supports the view that investments must be both used and useful and must be prudently incurred for the value of the resulting plant in service to be added to rate base.

If the tests are distinct and both are to be applied and met, does the order of application matter? Some would argue that the prudent investment standard should be applied first, and applied solely to the initial investment decision. Then the used-and-useful standard would be applied second, as a higher standard, once the investment is ready for rate base treatment. Here, the used-and-useful test substitutes for what competitive companies would call a market test of demand for their product. (Managers of competitive companies frequently make major investment decisions that are reasonable at the time, but turn out nevertheless to be wrong in the

sense that there is little or no market for their product. It is interesting to note that competitive companies are not unregulated, only less regulated. They are subject to environmental, occupational safety, tax, and many other regulations that are subject to changes which can affect the eventually profitability of an earlier investment decision.) Thus, in the case of a monopoly utility, if the initial decision to build a plant was prudent, but the plant is not used and useful when completed, then the plant could be excluded from rate base if the two distinct tests are applied in this order.

On the other hand, some would argue that the used-and-useful test should be applied first, and the prudent investment test applied second as a more exacting standard. The used-and-useful test would be applied to see if a plant is actually used in service and useful in providing service. If this initial test is met, then one could apply the prudent investment test to any doubtful investment decisions, from the initial decision to build the plant through the significant decisions involved in the construction of the plant and the final decision to complete the plant. The purpose would be to decide exactly how much of the expenditures on the plant were prudently decided. With the view that the prudent investment test and the used-and-useful test are two distinct tests, one can see that the order of application may affect the resulting rate base treatment of the investment.

The alternate view is that the prudent investment test and the used-and-useful test are very much akin, perhaps actually different aspects of the same rate base standard. Historically, it is clear that both the used-and-useful test and the prudent investment test are used in the determination and valuation of rate base. The used-and-useful test is an inventory-of-rate-base test that normally results in a simple "yes or no" determination of whether a facility is used and useful and should be included in rate base.[3] The prudence test, on the other hand, has been used as a

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[3]However, a commission may find that some components of total plant facilities are not used and useful and exclude these from rate base.

valuation test that determines how much of the investment is used and how many of the investment dollars were spent usefully as opposed to wastefully. It makes this determination by looking at the investment decisions at the time that they were made. Rather than being an inventory-of-rate-base test, the prudence test is a value-oriented test for determining the value of a facility that belongs in the rate base inventory. Viewed in this way, the prudence test is merely an extension of the used-and-useful standard, a particular way of expressing the capability of this standard to do more than a simple yes/no analysis. In this view, the prudence test is not a new test, but a newly emerging facet of the used-and-useful standard that is solidly entrenched in every state's public utility laws.

The relationship of prudence to a possible third investment standard needs to be resolved. This is the so-called least-cost investment standard. It requires that utilities actively investigate several ways of providing service so as to determine which is of least cost. For example, according to current thinking, electric utilities under this standard would have to consider a variety of ways of matching supply and demand, including extended service lives for older units, new alternate fuel technologies, cogeneration, long term power purchases, interruptible service, and utility-sponsored conservation programs. The issue here is whether the prudent utility decision maker must consider all such factors in the planning process and select the least cost strategy.

Recall that prudence is not a test of optimality in decision making; prudence does not require that the best investment decision be made, only that a reasonable one be made. On the other hand, it is typically said that regulated monopolies are expected to provide adequate service at "the lowest reasonable cost." The least-cost standard has firm legal standing when a utility faces clearly defined choices with predictable outcomes.[4] As alternative strategies for meeting electricity demand are increasingly studied and as analytical tools for comparing the long run values of these

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[4]See Atlantic Refining Co. v. Public Service Commission of New York, 360 U.S. 378, 388 (1959).

strategies continue to be developed, the standard of reasonableness may evolve. As it does, the distance between the prudence test and the least-cost investment test may shrink.

Hence, what needs to be resolved is how the used and useful standard, the prudence standard, and the least-cost investment standard relate to one another. Are they three aspects of a single standard for valuation of rate base, perhaps with any of the three aspects coming to the fore depending on the circumstances of the case? Or are these three distinct regulatory hurdles that a utility must leap over, one after the other, to receive rate base treatment of an investment?

Besides the issues about the nature of the prudence test, there are several issues to be resolved that relate to the use of the test. One issue is the regularity with which the prudence test should be used. Should it be a routine consideration in rate base valuation, or should it be reserved for occasions when there is overwhelming evidence for casting aside the presumption of prudence? As commissions evolve practices for using the prudence test, care should be taken, on the one hand, to avoid making the test routine, and, on the other hand, to avoid confining the applications so narrowly as to limit appropriate future use of the test. An important consideration here is the ease with which intervenors are permitted to challenge a utility investment on the basis of the prudence of utility decisions. Because of the costs involved, in time and manpower, to support a prudence inquiry, properly defining the level of proof required to overcome the presumption of prudence is vital.

A second issue about using the prudent investment test is the degree to which it should be used as a tool to help formulate commission policy. The prudent investment test lends itself to being developed and articulated in a manner that reflects commission policy and practice. It is important to recall that state commissions are quasi-judicial bodies, not judicial bodies, so that lack of a firmer legal basis for prudence is not as vital as it would be in a court. Thus, it is to be expected that a

commission would care less about the articulation of a concept than about gathering and weighing evidence in order to determine the facts of a case and the appropriate policy for the circumstances. In their role as policy makers, state commissioners can determine how the prudent investment test will apply to various types of utility investment decisions in various contexts and thus make clear to the managers of its regulated utilities what course of action is expected of them in new circumstances.

The prudent investment test is not, however, a tool for dealing with complex policy problems in a simple way. It is not a panacea; the application of the prudent investment test to complex issues is itself complex.

When the prudence test is used to determine the number of dollars of imprudently incurred expenditures, regulators may wonder about just how precisely this figure can be defined. In complex prudence investigations, such as those involving nuclear power construction, this will be a difficult task that requires judgment as well as data. It is not, however, an impossible task; juries in negligence cases, for example, routinely make similar judgments.

Another important issue that may emerge in actual uses of the prudent investment test is the question of to whom utility managers are answerable for their prudent decision making. State commissions need to understand to whom the standard of reasonable care is owed. Utility managers may make decisions that are in the best interests of the stockholders, the current ratepayers, future ratepayers, or society as a whole. If the prudent investment test is applied from other than the stockholder's point of view, application of the test causes a potential conflict between management's goals and society's goals. One duty of management to its stockholders is to maximize profits given the existing and anticipated regulatory constraints. Of course, utility managers look at the regulatory "rules-of-the-road" as they chart a course that they hope will maximize profits. As regulatory rules and applications change, managerial decision making

changes. Applying the prudent investment test from the stockholder's point of view avoids the divided managerial loyalty that results when the goals of the stockholders are not the same as those of society. Of course, applying the prudent investment test from the stockholders' point of view would make the test little more than a surrogate for other legal rights that protect stockholders, such as stockholder derivative suits, and would also do little to protect the utility customers.

Alternatively, the prudent investment test could be applied to see if decisions were prudently made on behalf of current ratepayers. That is, were utility decisions directed toward providing adequate service at just and reasonable rates today? Managers are expected to make decisions directed toward this goal because the utility accepts this goal when it accepts the franchise to provide service. However, applying the prudent investment test on behalf of current ratepayers is not without difficulties. Consider the case where a utility has a generating unit that is three-fourths completed when it finds that the plant is no longer required. To make the example simple, suppose it is in a situation where, if the costs of abandoned plant could not be recovered in rates, the abandonment would mean, if not bankruptcy, very high capital costs in the future. This will impose a cost on future ratepayers. This cost can be avoided if the unit is completed, but this action imposes a cost on current ratepayers. Setting aside management obligations to investors, what is the prudent decision for management? Should it decide solely on the basis of current ratepayer interests, or does it have an obligation to keep the company financially sound so that adequate power is available at reasonable rates in the future?

If some weight is to be given to the interests of future ratepayers, perhaps all parties' interests should be taken into account in the prudent decision: current ratepayers, future ratepayers (with appropriate discount factors), investors, utility employees, state treasurers, and so on. If the decision is based on all parties' interests, properly weighted, then the decision may be prudently made from the viewpoint of society as a

whole. This is a proper viewpoint for commissioners to take as agents of state government, but the hardest to deal with in the hearing room.

The prudent investment test, if applied to protect society as a whole, would give due recognition to the quid pro quo nature of the arrangement between the regulated utilities and the commission qua state. The utility is to receive reasonable compensation for providing adequate service in exchange for being granted a territorial monopoly. The utility knows it will not be allowed to earn extraordinary profits, but expects it will be protected from certain losses, at least the loss of business to competitors. Because a utility is a regulated company acting in the public interest, it must provide service at the lowest reasonable cost consistent with adequate and reliable service, as indicated in the Atlantic Refining Company case cited above. If this duty is owed not only to current ratepayers but to future ratepayers, the utility should continue to take into account the needs of future ratepayers in its utility investment decisions. Then a state commission, in applying the prudent investment test, would want to judge whether utility management sought to protect the interests of future as well as current ratepayers when making investment decisions.

As state commissions develop the prudent investment standard, it is important that the regulatory "rules of the game" be as explicit as possible. Otherwise, utility managers may justifiably complain that, in aiming at achieving a reasonable utility investment decision-making process, they are trying to hit a shifting target. Managers need to know what the standards are by which they will be judged in order to decide with confidence. The use of the prudence test should not be so uncertain that managers are afraid to make decisions. After all, a decision not to decide or a failure to manage can also be imprudent. The proper role of management is to manage, not to allow events to run their course.

Clarifying the role of prudence is not only in the managers' interest; it helps to further the objective of having a prudence test. This

objective is to make utility managers more cognizant of the import of major investment decisions. The test, properly used, can have a "cleansing effect" on the managerial decision-making process, leading to better utility investment decision making. Use of the test need not mean managerial paralysis if the ground rules are understood by all parties.

Commission Involvement in the Decision-Making Process

As shown in chapter 4, the risks that utilities face today in making investment decisions are significantly greater than in earlier years, and the consequences are greater also. Because of these factors, the prudent investment test has emerged as a tool frequently used by state commissions to allocate risk between customers and investors. Now many state regulators, legislators, and governors are seeking to have state commissions become more involved in the utility decision-making process. This involvement is aimed at ensuring better decisions and lowering the level of risk. Sometimes a supplementary goal is to recognize that, when regulators must allocate a large share of the risk to ratepayers, regulators should participate in the decision-making process. Utility representatives seem divided on the question of greater commission involvement, some objecting to infringement of management prerogatives and others welcoming a process that they see as shifting more of the risk onto utility customers. The prudent investment test may act so as to define the boundary between commission regulation and managerial prerogative.

Several issues are involved in use of the prudent investment test where commissions participate to some degree in either making or approving investment decisions. The fundamental issue is whether state commissions ought to become very involved in the utility investment decision-making process on an ongoing basis. Such involvement could take the form of periodic prudence reviews or of an immediate review of each major utility investment decision as it takes place.

Several factors favor greater commission participation in approving investment decisions by utilities. The most important factors relate to the opposing threats of future excess capacity and future capacity shortages for electric utilities. Excess capacity resulted from overly optimistic utility views on the growth potential of the industry, and many regulators believe that greater commission involvement in deciding future capacity needs will assure a more realistic judgement about demand growth. This, in turn, would protect commissions in the future from facing major bankruptcy-versus-rate-shock decisions related to overcapacity. If commissioners believe that rate base exclusion of major investments is realistically impractical, they have a special incentive to review the investment decision before the funds are committed.

On the other hand, without an assurance of favorable regulatory treatment, utilities are likely to underinvest in new capacity, for the reasons set out in chapter 5. Regulators would give such an assurance only if they were very involved in the utility decision-making process on an ongoing basis. Absent early commission approval of a major construction project, the utility would be reluctant to undertake construction if the possible rewards were small or nil and the possible penalties large. However, a utility would be encouraged to make investments in needed plant if the commission determined, once and for all, the prudence of the investment decision at the earliest planning stages, or if the commission participated in periodic prudence reviews during construction.

Another factor favoring greater commission involvement in major utility decisions is risk reduction and hence capital cost reduction for utilities. In a regulatory environment where the commission withholds judgment on the acceptability of investments for 10 years or more, investors require a risk premium in the form of higher return on debt and equity if they fear that the commission may reject some or all of the investment expenditures as imprudently incurred. If early commission involvement assuages this fear, the utility's cost of capital is lower and the ratepayer's cost of service is lower.

However, if the objective that state regulators seek to achieve is better utility investment decision making so that society as a whole benefits, then involvement by a state commission or other state agency in the decision-making process might be ineffective or counterproductive.

Commission participation in, or even periodic review of, the decision-making process would require significant staff resources and levels of expertise. Otherwise such participation could be ineffective. It is easier for utilities to know their own business and to carry it on than it is for commissions and their staffs to try to duplicate the decision-making machinery of a utility. Without adequate staff resources, there would always be a question about whether the staff carries out a truly independent review of the decision. The difficulty is that the commission, in supporting its own staff's analysis, may in effect feel bound to support a utility decision that may not be adequately reviewed.

With state commission involvement, there might be less incentive for the utility managers to use the best available decision-making procedures. Instead, decision making may be only as good as "the state" requires. Further, regulators may favor a new technology (such as photovoltaics, wind generation, or geothermal generation) or a mode of balancing supply and demand (such as conservation, reliance on cogeneration, or interregional purchased power), which may not ultimately prove to be the most reliable and economical power supply strategy. Yet, utilities might adopt a less-than-optimal power supply plan if this assured regulatory preapproval of construction plans.

Regulatory preapproval suggests two closely related issues that arise with greater commission involvement: the possibility of co-optation and the possibility of a regulatory estoppel. If a commission (or other state agency) takes part in the utility investment decision-making process--by being directly involved in demand forecasting and capacity expansion planning and by reviewing all subsequent major utility investment decisions--the commission might be unwilling to find a decision to be imprudent. By

taking part in the decision-making process, the commission may step away from its role of judge and take up the role of defender of the decision.

In this way, participation in the decision-making process may lead to co-optation. If the commission or other state agency actually takes part in the decision-making process and is therefore reluctant to find that an investment decision was imprudent when made, the result will be that the utility customer must bear the risk of poor decisions. If commission participation leads to better decisions, perhaps the ratepayer will be satisfied. If it does not, the ratepayer may view commission participation as a mistake, especially if it seems that the reason for commission inaction is that the commission feels bound by its prior review.

Even if the commission does not feel bound by its taking part in utility decision making, the commission might nonetheless actually be bound by the operation of a regulatory estoppel, a legal principle that could prevent the commission from penalizing a utility for an imprudent decision in which the commission took part. The legal doctrine of estoppel operates to prevent miscarriages of justice when one party has justifiably relied on another and the first party has suffered a detrimental change in position.[5] This doctrine might prevent a state commission from disallowing investment expenses incurred by the utility if the investment decision was given prior approval by the commission. A regulatory estoppel might also prevent the commission from penalizing a utility for an imprudent decision in which another state agency took part. The operation of a regulatory estoppel would lessen the risks that a utility faces in making an investment decision. But it would have the same pitfalls as co-optation and do as little to assure that good decisions are made.

Whether a regulatory estoppel would actually operate is as yet unclear. However, there are some indications that the courts would weigh

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[5]The doctrine of estoppel was described in detail in the preapproval study referred to earlier. See Russell J. Profozich et al., Commission Preapproval.

commission involvement in decision making heavily to the point where any subsequent denial of cost recovery might represent confiscation. The issue of a regulatory estoppel has already arisen in the context of whether a state commission can refuse to permit a utility to recover the costs of a cancelled plant, based on the used-and-useful test: a Wyoming Supreme Court decision affirmed the Wyoming Public Service Commission's denial of cost recovery, but stated in dicta that its decision would have been different if the commission had granted prior approval to the utility before entering into the project.[6] In effect, the court ruled that prior approval of major utility expenditures could create an equitable estoppel that would prevent a commission from disallowing utility expenditures on an investment in plant that was later cancelled, abandoned, or otherwise not brought into service.

An estoppel can operate only if a utility justifiably relies on the state commission's prior approval of an investment. A utility's reliance would not be justifable if the utility makes imprudent expenditure decisions not directly approved by the commission. For example, a commission's prior approval of a utility's investment in a nuclear unit need not prevent the commission from later disallowing associated investment expenditures that are incurred in excess of what is reasonably required. Nevertheless, a state commission would be well advised to specify in an order granting prior approval to a major utility investment that only reasonable expenditures will be recoverable.[7]

Regulatory estoppel presumably would not operate if, after commission approval of a major construction project, conditions change sufficiently to occasion a re-examination of the project. However, an equitable estoppel might operate to keep a state commission from finding that investment expenditure decisions in an ongoing utility project were imprudent if the commission were to review the progress of the project periodically or were

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[6]See Pacific Power & Light Co. v. Public Service Commission, 677 P.2d 799 (1984).

[7]Russell J. Profozich et al., Commission Preapproval, at pp. 35-38.

otherwise involved in oversight of project construction. Granted, if a commission were to become highly involved in reviewing a construction project, it might better judge the prudence or imprudence of management decisions while the facts are still fresh, without the danger of engaging in hindsight years later.[8] But, a commission and its staff may work best in retrospect, rather than "on the job."

The heart of the issue is whether regulators ought to create procedures for prospectively assuring prudence that are so detailed that the concept of prudence becomes unnecessary as a tool for retrospective review, or whether they ought to abstain from participating in utility decisions in order to reserve the right to review and criticize these decisions.

Limitations on Applying the Prudence Test

A third set of issues relates to how far state commissions can or should go in applying the prudent investment test where a very large utility investment is involved. Clearly, the results of applying the test in a particular circumstance depend greatly on the judgment of the decision makers. If that judgment is to make utility investors bear the full burden of an imprudent decision, how burdensome can the treatment be before the courts will overturn the commission decision?

As discussed in chapter 2, the end-result test of Hope sets the outer boundary of a prudent investment test application. This is that the prudent investment test (or any other valuation method for that matter) cannot be so applied as to reach a confiscatory result. Confiscation takes place whenever there is a taking of property without just compensation. For a regulated industry, this occurs if it is not allowed an adequate return on its investment.

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[8]Ibid., p. 40.

The courts have repeatedly ruled that keeping property out of rate base because it is not used and useful does not result in confiscation. It is not yet clear whether rate base exclusion based on a finding of imprudence would be viewed as confiscatory. Recalling our earlier discussion, if the prudent investment test is found to be merely an aspect of the broader used and useful standard, then its use presumably would not be confiscatory.

However, if the prudent investment test is viewed as a distinct test from the used and useful test, then the resolution of this issue is less certain. It might be that an application of the prudent investment test would not lead to a confiscatory result because confiscation does not take place if management is found to be inefficient. This is because a return would be considered adequate if, under efficient management, it would maintain and support the utility's credit and allow the utility to raise the money necessary for the proper discharge of its public duties.[9] In other words, if management is found to be inefficient, then it cannot be said that the return is inadequate solely because of an application of the prudent investment test. No confiscation would have taken place due to the application of the test.

On the other hand, if the prudent investment test and used and useful test are viewed as distinct, the prudent investment test may be judged as conflicting with the used and useful test, which has the firmer statutory basis. Then a finding might be possible that an application of the prudent investment test resulted in confiscation. In any event, future challenges, if any, to the prudent investment test on the grounds that the application of the test leads to a confiscatory result must be on a case-by-case basis, and according to Hope only the particular end result could be held to be confiscatory. Hence, the prudent investment test itself would likely survive the challenge.

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[9]See Bluefield Waterworks & Improvement Co. v. Public Service Commission, 262 U.S. 679, 692-693 (1923).

how "useful" utility property is--both in an absolute sense and in a relative sense. Many circumstances may be considered by regulators in the name of prudence--cheaper capital alternatives that were available at the time planning decisions were made, the effectivenes of cost controls for capital projects, the validity of demand forecasts, and project necessity, to mention only a few. Clearly, not every capital investment alternative is equally "useful." Prudence provides a qualitative means of assessing the degree to which investments are "useful," by potentially allowing less than full costs incurred to be utilized in rate calculations on the basis of the worthiness of the costs. Prudence is not confined, however, to the capital cost component of ratemaking, for it may be used to assess the quality of operating expenses as well as to examine the worthiness of their incurrence. In these ways, prudence can be, and is being, used in the traditional ratemaking determination, a process that is no longer an esoteric accounting exercise confined to the bowels of utility commission hearing rooms.

Because of increased public awareness of the financial condition of utilities, particularly electric utilities, more public attention is drawn to rate proceedings. The recent cover story in Business Week magazine, entitled "Are Public Utilities Obsolete? A Troubled System Faces Radical Change,"[11] is but one example of the increasing public attention that is being focused on the many issues facing electric utilities today. Certainly, Congressional consideration of many of the issues facing public utilities has had the effect of focusing increased public attention on the matter.[12] And significant and fundamental changes in the existing

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[11]"Are Utilities Obsolete? A Troubled System Faces Radical Change," Business Week May 21, 1984, p. 116.

[12]See, for example, "U.S. Electric Power System Reliability," Hearings before the Subcommittee on Energy Development and Applications of the House Committee on Science and Technology, 97th Cong., 2d Sess. (1982); "Centralized vs. Decentralized Energy Systems: Diverging or Parallel Roads?" (Committee Print), Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, 96th Cong., 1st Sess. (1979); "U.S. Energy Outlook: A Demand Perspective for the Eighties," (Committee Print), House Committee on Energy and Commerce, 97th Cong., 1st Sess. (1981); "Are the Electric Utilities Gold Plated? A Perspective on Electric Reliability," (Committee Print), Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, 96th Cong., 1st Sess. (1979).

regulatory framework are being advocated.[13]

Yet, despite this public attention a utility's rate proceeding continues to be the significant pressure point in the existing regulatory framework that provides accountability to the consuming public and the investing public. Traditional rate methodology may not be providing a wholly satisfactory mechanism for the solution of the many issues facing utilities, although rate methodology continues to be discussed extensively.[14] One recent article described the continuing utility rate controversy this way:

> Valuation of public utility property for rate-making purposes has been controversial since the beginning of public regulation. Despite much academic research and practical experience, there is no consensus of academician or practitioners concerning the appropriate value of physical property used for providing service to customers.[15]

But the study underscored the inadequacy of the traditional rate methodology debate because it showed "...no systematic relationships between methods of rate base determination and profits or prices charged by electric utility firms [because] [r]egulatory commissions were usually

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[13]See, for example, Pierce, "Reconsidering the Roles of Regulation and Competition in the Natural Gas Industry," 97 Harvard Law Review 345 (1983); and Collins, "Electric Utility Rate Regulation: Curing Economic Shortcomings Through Competition," 19 Tulsa Law Journal 141 (1983).

[14]See generally, Mullin, "Rate of Return Determination in Nebraska," 7 Creighton Law Review 206 (1974); Comment, "Determination of Allowable Rate of Return by the Texas Public Utilities Commission," 57 Texas Law Review 289 (1979); Comment, "Due Process: Applicability to Utility Rates," 42 Missouri Law Review 152 (1977); Levin, "Illinois Public Utility Law and the Consumer; A Proposal to Redress the Imbalance," 26 DePaul Law Review 259 (1977); Demet and Demet, "Legal Aspects of Rate Base and Rate of Return in Public Utility Regulation," 42 Marquette Law Review, 331 (1959); and Comment, "Reassessing 'Confiscation' Under Section 305 of Maine's Public Utility Law," 29 Maine Law Review 194 (1977).

[15]Primeaux, Bubnys, and Rasche, "Fair Value Versus Original Cost Rate Base Valuation During Inflation," 5 Energy Journal 93, 93 (1984).

either overcompensating or undercompensating for inflation occurring in the economy."[16]

Because of the increased scale of operations and economic decision making being undertaken by utility management, encouraging efficiency and prudence by management for the ultimate benefit of the public and ratepayers has become a dominant theme in utility oversight. According to one analyst of modern finance theory,

> [t]here exists, however, a set of problems that will continue to be with us whichever approach is used [for ratemaking]. Among these are...[h]ow to compensate efficiency and penalize inefficiency. A well-managed, efficient company should be entitled to share to some extent the benefits resulting from an efficiently run operation. Similarly, an inefficient company should be forced to bear the costs of inefficiency. The mechanics of developing a system that would resolve this point in an equitable manner faces regulators today and will continue to face them under the proposed approach.[17]

The stark reality of financial problems confronting the electric utility industry raises some very profound problems beyond simply establishing a means through the rate system to reward soundly managed and efficiently operated utilities. Clearly, many utilities presently face difficult financial problems that are the product of investment decisions made long ago. The solution to those financial problems may not be quite as simple as the adoption of abbreviated regulatory methodology:

> The fiscal problems of the utility industry will not be solved by financial innovations or gimmickery. Any new development in utility financing must come gradually. Its soundness and validity must be carefully scrutinized and tested, and it must be consistent with outstanding obligations and investment standards. That great change has already taken place reflects not only the extreme financial pressures on the industry, but the willingness of issuers and investors to

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[16] Id., p. 94.

[17] Alexander A. Robichek, "Regulation and Modern Finance Theory" 33 Journal of Finance 705 (1978).

> accept something new which responds to changing conditions without varying extensively from past practice. Yet all financing, whether conventional or innovative (a much misused and misunderstood word in this connection), must rest ultimately on the fundamental economic soundness of the industry and the particular company within that industry. It is the credit of the company which supports all financing, whether it be joint ownership, project financing, leasing, some variant of debt or equity or conventional issue. Only if the utility has adequate earnings, made acceptable to the public and regulatory authorities through good service and capable management, can the financial future of the electric utility industry in this country be assured. [Emphasis added.][18]

The prudent investment concept, as a supplement to traditional rate methodology, may provide the means for a new regulatory "hard look" at utility management decision making. A recent summary of what might be described as the modern usage of the prudent investment concept is applicable generally to other aspects of utility regulation:

> Public utilities have an obligation to operate their business in a reasonable, prudent and efficient manner for the benefit of their customers. This well established principle may have practical application to access questions in those cases where electric utilities or gas pipelines have significant unused capacity. The question in such cases is whether the utility's or pipeline's failure to seek the business of willing, would-be customers constitutes imprudence or inefficiency.
>
> The cases suggest that management imprudence or inefficiency is a broad concept. Thus, clearly excessive payments for various inputs can be disallowed. The cases likewise suggest that while management decisions, prudent when made, will not be judged by hindsight, the failure to make cost efficient decisions may be reflected in reduced rate allowances. In that sense, lost savings opportunities as well as unnecessary expenditures can be attributed to the utility.
>
> It is through the concept of foregone savings that prudent management principles may affect the availability of pipeline and transmission facilities. In Public Service Co. of Indiana, [10 F.E.R.C. para. 61,236] the [Federal Energy Regulatory] Commission stated that prudent management obligations might require public utilities to seek cost-saving power pooling opportunities, and hinted

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[18]Katzin, "Electric Utility Financing Today," 55 Oregon Law Review 479, 491 (1976).

that the failure to seek reasonably available savings might be examined in future rate cases. The reasonable implication to be drawn from the Commission's statements is that under-utilization of pipeline and transmission capacity may also be open to examination. Full utilization of facilities, to the extent that revenues from new customers can cover variable costs and defray fixed ones, may be deemed the prudent course, with foregone revenues attributed to the pipeline or utility involved.

This is not to suggest that claims of imprudence will always be successful. There may be legitimate reasons for maintaining unused capacity, for example. Or, the utility or pipeline may simply accept the rate penalty rather than provide access to a competitor. Moreover, whether or not a bottleneck exists should have some bearing on the obligation to provide access. Thus, absent monopoly power, the refusal to deal may simply be a reasonable election by the pipeline or utility involved. On the other hand, where the essential nature of the facility is demonstrated, the refusal to serve for anticompetitive reasons, and the loss of revenues suffered as a result, might indeed support a rate reduction based on a finding of imprudence....

Rapidly escalating prices for natural gas and electric energy charged by major gas pipelines and electric utilities have forced consumers, particularly gas and electric distribution systems, to increasingly seek a means to contain their costs. Competitive solutions, i.e., reliance on market forces, depend upon the availability of supply options. Access to the wholesale supplier's gas pipeline system or electric transmission network is often essential to any customer plan for the development or acquisition of alternative gas or energy sources. [Footnotes deleted.][19]

Certainly, one of the most important issues raised with regard to utility performance is the relationship between the quality of service offered by the utility and the level of rates allowed. One summary of the relationship expresses it this way:

> The three ways to protect the public interest by "quality of service" are (A) making the rate base dependent upon the "adequacy of service" provided, (B) insuring that management decisions by the public utilities are in the public's best interest, and (C) allowing the

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[19]Reiter, "Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation under the Federal Power and Natural Gas Acts," 18 Land and Water Law Review 1, 79 (1983).

about the usefulness of property already in existence and an after-the-fact judgment about whether existing property is in actuality being used to discharge service to the public. The used-and-useful requirement, based both on Bluefield and contemporary statutory prohibitions, often prevents the incorporation of property into the rate base while construction is in progress and therefore necessarily mandates an evaluation of the property for rate purposes after it has come into existence. In short, the constitutional and statutory criteria for ratemaking are retrospective.

The current rate process does not normally provide for a mechanism to evaluate proposed investment decisions or operating expense decisions of public utilities in advance of the actual outlay of funds or the making of long term financial commitments. But, there is nothing inherent in the concept of prudent investment that limits it to a retrospective evaluation.

Under a changed regulatory framework, the concept of prudence could easily be used in a prospective sense to assure the recovery of investment costs by blessing certain investment decisions as they are being made, or before they are made. But such a scheme would require a more nearly perfect predictive ability to fix costs in advance, to project the usefulness of utility property, to project utility demand for services, to forecast the national economy, and to speculate about many other future occurrences. Even if such a system could be adopted as a regulatory incentive toward sound planning by locking in a guaranteed return in advance of actual investments, leaving the financial effects of good planning and bad planning to the exigencies of the future would provide little assurance to the public of efficient future utility operation. Bad guesses approved in advance and locked in place by regulatory approval would only lead to a decline in the ability of a public utility to discharge its public service obligations.

The concept of prudent investment should be seen, under the existing regulatory framework, as a way to place the appropriate amount of risk of utility mismanagement on utility equity owners. The fact that the risk

may not be exclusively economic because of the use of a regulatory requirement of prudence is not particularly significant, for the marketplace provides little ability to enforce sound investment or expenditure requirements on monopoly utilities apart from the regulatory process anyway. The prudent investment concept as applied in public utility regulation involves many of the very same judgments that are made legally about management investment decisions in analogous fields. The major areas of trust supervision and oil and gas leasing, as well as corporate obligations to shareholders, all involve particular legal obligations to make sound (read "prudent") investment decisions. All contain a significant measure of retrospective evaluation, and all are imposed for essentially the same reasons: protecting proprietary interests of investors or owners, where they have assigned legal managerial control to others. In this regard, public utilities are no different. Utilities are assured, through regulation, a fair return for business activities conducted on behalf of their investors and of their customers. The question that remains, however, is the extent to which the public should be at risk for decisions over which it presently exercises little or no advance control except through regulation.

The problem of adjudging the conduct of financial affairs by public utilities argues strongly for improved regulatory controls, like the use of the prudence test, to assess utility financial decision making.

What is needed, however, is a more specific elaboration of the case-by-case application of the prudent investment standard in order that its later application can be anticipated at the time investment decisions are being made by utility managers. As a device for the solution of the current dilemmas of utility managers and utility regulators that have been created by overconstruction and excessive demand projections, the prudent investment test is limited. The concept of prudent investment provides at best an imperfect solution to the problems raised by unwise decisions of the past.

Prudence nevertheless offers a regulatory opportunity within the existing framework to deal with many existing and future utility issues. The breadth of discretion and flexibility that prudence offers can be assumed to be constitutional under the result-oriented doctrine of Hope, so long as the use of the concept does not have a confiscatory result. While the regulatory flexibility of prudence provides an advantage, the attendant potential for misuse must be avoided through its sound application.

It can be fairly asserted in today's regulatory scene, where rights are balanced with duties, that the substantial benefits derived from the exclusive right granted to utilities to do business in a particular territory require more rigorous regulatory attention to the manner in which that business is conducted. The scale of investments and the degree of risk to investors and the public ratepayers can be substantial. The proper use of the prudent investment obligation can put the economic risk where it belongs--with the utility owners and their management agents.

PHMSA

Final Report No. 15-019

Final Report

Repair/Replace Considerations for Pre-Regulation Pipelines

J.F. Kiefner and M. Van Auker

March 11, 2015

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Final Report

On

REPAIR/REPLACE CONSIDERATIONS FOR PRE-REGULATION PIPELINES

DTPH5614H00006, REPAIR/REPLACE CONSIDERATIONS FOR PRE-REGULATION PIPELINES

to

U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

March 11, 2015

by

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EXECUTIVE SUMMARY

The objective of this project was to develop a standardized process for making repair/replace decisions for pre-regulation pipelines to assure that they will be replaced if they deteriorate to the point that their integrity and safety can no longer be maintained. Pre-regulation pipelines are those that were installed prior to November 12, 1970 when Federal pipeline safety regulations were first promulgated. The guidelines provide a standardized method for pipeline operators to decide which of their pre-regulation pipelines can be maintained safely and which of them should be replaced because of technical and/or integrity shortcomings that cannot be satisfactorily mitigated at an acceptable cost. The guidelines are intended to apply to hazardous liquid pipelines, natural gas transmission pipelines, and natural gas distribution systems. Pipeline operators would need to apply repair/replace processes in a manner that meets the operational and integrity standards of all applicable Federal and State pipeline safety codes.

These guidelines focus strictly on technical and safety related factors that must be addressed to safely maintain a pre-regulation pipeline, in service, independent of the cost or the convenience. It is recognized that no realistic repair/replace decision scenario is independent of considerations for feasibility, cost-benefit analysis, restrictions on cost recovery through rates, and assessment of risk, which are matters not addressed in this report. However, it is expected that pipeline operators will apply their own analyses to these latter aspects of a repair/replace decision.

The guidelines presented herein are intended to assist a pipeline operator in deciding whether or not to replace a given pre-regulation pipeline or distribution system. Replacement is not necessary if it is feasible to continue to maintain the integrity of the pipeline, main, or service through on-going integrity assessments and mitigation of findings. This report provides criteria for assessing what is required to preserve the integrity of a pipeline to assure that it does not constitute a substantial risk to public safety. The guidelines also show what should be done to maintain the integrity of an existing main or service operated under Part 192, Subpart P, "Gas Distribution Integrity Management". Examples of hypothetical pipelines, mains, and services are presented. These examples illustrate how an operator can consider pipeline attributes, potential threats to pipeline integrity, and mitigative responses that would be required to make a decision either to do what is necessary to maintain the integrity of the pipeline and continue to operate it or to replace it. It is up to the operator to decide whether or not pipeline integrity can or will be preserved via the necessary maintenance and repairs or whether, instead, the pipeline, main, or service will be replaced.

The process for making repair/replace decisions in each case is based on a series of flow charts. It will be seen that these flowcharts constitute prescriptive procedures for making repair/replace decisions. These procedures are not meant to prevent a pipeline operator from conducting an engineering critical assessment of a pipeline that would allow the decision to be made outside of these prescriptive procedures.

The process of deciding whether to repair or replace depends on having the essential data on the pipeline, main, or service. Certain data are essential if the pipeline or distribution system component is to remain in service. The essential data include but are not necessarily limited to the type and vintage of pipe; its mechanical properties; the type of coating on the pipe (unless it is plastic pipe); the operating pressure of the pipeline as a function of time; the leak and rupture history of the pipeline, main, or service; and the pressure test history. These guidelines define which data elements are essential for deciding whether or not a given pipeline, main, or service should remain in service.

Repair/replace decisions also depend on recognizing and addressing threats to pipeline integrity, in particular, those threats that are of a time-dependent nature and could affect the pipeline, main, or service anywhere along its length. Time-dependent threats that could affect pipeline integrity globally are the drivers for repair/replace decisions. These include external corrosion, internal corrosion, selective seam weld corrosion (SSWC), stress corrosion cracking (SCC), pressure-cycle-induced fatigue (PCIF), and slow crack growth in the case of plastic pipe. Replacement is not an appropriate means to deal with threats that tend to be random in nature or that affect only specific areas such as mechanical damage and outside forces. Replacing a pipeline, main, or service would be an inefficient reaction to such threats. Replacing a pipeline, main, or service also is not a solution for threats such as equipment failure and incorrect operation.

Replacement of a pipeline segment, a main, or a service is not necessary if the operator can afford to mitigate the active time-dependent threats such that the risk of pipeline failures from such threats is acceptably small. Replacement becomes necessary whenever one or more of the "driver" integrity threats cannot be mitigated and the risk of failures is not acceptably small. Replacement also may become the best choice where addressing the threats and/or assuring safety is technically feasible but the cost of properly addressing the threat and/or assuring safety is more than the cost of replacement.

The time-dependent nature of the driver threats implies that mitigative responses must either be continually or periodically applied. This, in turn, implies that reassessment intervals must be estimated for each active threat that must be addressed periodically. The adequacy of the re-assessment interval is validated by the absence of frequent in-service failures from time-dependent threats over the life of a pipeline or by experience that reflects a declining or steady-

state leak history for a distribution system main or service. Replacement is likely to become the preferred option to a continuing re-assessment and repair program when the cost of the latter exceeds the cost of replacement. But, in any case it will be up to the operator to decide. The criteria presented herein are intended only to give the operator a sound technical basis for defining a mitigative repair plan, one that would be expected to prevent in-service failures of a pipeline from time-dependent threats or that avoids an increasing leak rate in a distribution system main or service.

In some cases the appropriate time for replacement can be deferred if the rate of degradation is slow enough. Lowering the operating pressure of a pipeline in stages may be one way to extend the time before replacement is needed because the effect of lowering pressure is to reduce the likelihood of a failure from time-dependent degradation. In the case of a main or service, replacement can be deferred if there is a likelihood that the leakage rate will not increase with time.

Replacement may also be deferrable if a repair or operational change mitigates or eliminates a specific time-dependent threat even if prior in-service failures have occurred due to that threat. Examples:

- The pipeline is recoated to prevent external corrosion or to replace a coating that shields the pipe from cathodic protection to mitigate SCC.
- Cathodic protection is enhanced such that external corrosion is mitigated.
- The maximum operating pressure is reduced to a level that mitigates exposure to SCC or PCIF.
- An operational change involving increasing flow velocity above the water entrainment threshold or change of service to a less corrosive product to mitigate internal corrosion.

This document begins with a background section, a list of acronyms used throughout the document, and a list of definitions applicable to repair/replace decision making. The guidelines are then presented in three main segments:

1. Factors to Consider in Making Repair/Replace Decisions
2. Mitigative Responses to Avoid or Delay Replacement
3. Criteria for Making Repair/Replace Decisions

The third segment presents numerous examples of the process of making a repair/replace decision for the three types of pipeline systems (hazardous liquid pipelines, natural gas transmission pipelines, and natural gas distribution systems).

The user of this document must refer to the governing Federal and/or State pipeline safety codes and referenced standards to properly implement this guidance document and to maintain safety.

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Repair/Replace Considerations for Pre-Regulation Pipelines

J.F. Kiefner and M. Van Auker

BACKGROUND

Based on data submitted through natural gas transmission 2012 annual reports to the Pipeline and Hazardous Materials Safety Administration (PHMSA), 176,363 miles of the 298,422 miles of natural gas transmission and gathering pipelines in the U.S. (59%) are "pre-regulation" pipelines, that is, pipelines installed prior to 1970, when Federal pipeline safety regulations went into effect. Based on data submitted through hazardous liquid pipeline 2012 annual reports to PHMSA, 97,316 miles of the 185,922 miles of hazardous liquid pipelines in the U.S. (52%) are "pre-regulation" pipelines. As shown in Appendix A, trends of annual mileage show that these numbers are gradually decreasing due to some older pipelines being taken out of service or replaced. Older pipelines are not necessarily less safe than more modern pipelines. If their integrity can be maintained by appropriate and timely inspections followed by remedial responses to restore their serviceability, they can continue to operate without excessive risk to the public. The primary reason for conducting this project was to develop guidelines that pipeline operators can use to determine when replacement makes more sense than continuing to do the necessary repairs to maintain serviceability of a pre-regulation pipeline

In response to concerns raised by PHMSA and the National Transportation Safety Board (NTSB) with regard to the safety of these older pipelines, the Interstate Natural Gas Association of America (INGAA) has developed a fitness-for-service (FFS) process that a pipeline operator may use to assess the safety of pre-regulation pipelines, expecting that over time operators will adopt the process in making repair/replace decisions regarding their pre-regulation pipelines.

To aid pipeline operators with making repair/replace decisions, this project was initiated to create guidelines for implementing and executing a pre-regulation pipeline repair/replace program. While INGAA's approach to FFS for natural gas transmission pipelines was considered in this work, the guidelines described in this document were tailored not only to natural gas transmission pipelines but to the special concerns associated with natural gas distribution systems and hazardous liquid pipelines as well. The resulting guidelines may be suitable for inclusion in consensus pipeline safety standards including ASME B31.4 and ASME B31.8.

These guidelines were developed with the view that all pipelines of all types are "pre-regulation" pipelines if installed prior to November 12, 1970. The rationale for using one date

for all types of pipelines is that the materials and construction methods and most of the risks associated with pipelines are similar irrespective of the type of service (liquid[1] or gas[2]).

In general, operators of natural gas transmission pipelines and hazardous liquid pipelines seldom consider replacing a pipeline because satisfactory tools are available to periodically assess the integrity of their pipelines, namely, in-line inspection, hydrostatic testing, and direct assessment. Operators who employ these techniques at timely intervals based on engineering analysis and actual operating experience and respond in a timely manner to repair anomalies discovered during the assessments have established remarkably good safety records. Nevertheless, there may be cases where conducting the necessary periodic integrity assessments needed to prevent failures is not feasible. For those cases the guidelines developed on this project can be a useful decision-making tool.

In contrast to the transmission segments of the pipeline industry, the natural gas distribution industry for more than 40 years has considered and often chosen pipe replacement as another alternative to continued repair and mitigation activities. There are two reasons for this. First, some distribution systems contain mains and services comprised of obsolete materials, mainly cast iron pipe and uncoated steel pipe that are subject to severe degradation resulting in numbers of leaks out of proportion to the amounts of such materials in the systems. Second, the nature of distribution piping systems is such that the standard integrity assessment tools, in-line inspection, hydrostatic testing, and direct assessment are generally not applicable. Distribution operators with systems containing obsolete materials generally have often established replacement schedules based on available prioritization models. These circumstances have led the industry, through the American Gas Association, to assemble a compendium of papers describing the repair/replace strategies used by various operators, consultants, and research organizations[i]. The facts that about 60,000 miles of cast iron mains were in service in 1984 and that less than 34,000 miles of cast iron mains were still in service in 2011 show that the amount of replacement has been significant.

With the promulgation of 49 CFR 192, Subpart P, "Gas Distribution Integrity Management" in 2009, operators of gas distribution systems must establish a Distribution Integrity Management Program (DIMP) that covers all parts of each distribution system. Prior to the DIMP regulation, gas distribution operators had company specific policies and procedures to safely manage their distribution systems. While many gas distribution operators already have repair/replace programs in progress based on proprietary models, the DIMP regulations may change the way

[1] Hazardous liquid pipelines are governed by 49 CFR Part 195, which was effective on April 1, 1970.
[2] Natural gas pipelines are governed by 49 CFR Part 192, which was effective November 12, 1970.

distribution operators execute repair/replace decisions. The DIMP regulations require a distribution operator to:

1. Develop and implement a written integrity management plan.
2. Know its infrastructure.
3. Identify threats, both existing and of potential future importance.
4. Assess and prioritize risks.
5. Identify and implement appropriate measures to mitigate risks.
6. Measure performance, monitor results, and evaluate the effectiveness of its programs, making changes where needed.
7. Periodically report a limited set of performance measures to its regulator.

Accordingly, the guidelines developed on this project must embody the DIMP approach to identifying and mitigating integrity threats. Among other things, the current work is aimed not just at cast iron and bare steel where replacement often makes sense. This project is intended to address other material and construction related threats such as the phenomenon of slow crack growth in polyethylene (PE) plastic pipe. In such cases, successful mitigation of threats is likely to become the preferred option to replacement.

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ACRONYMS

A/A	Additional or accelerated (actions that a gas distribution operator may need to take in order to comply with DIMP)
CFR	Code of Federal Regulations
49 CFR 192	That part of the Code of Federal Regulations which applies to natural gas transmission pipelines and natural gas distribution systems
49 CFR 195	That part of the Code of Federal Regulations which applies to hazardous liquid pipelines
CMFL	Circumferential magnetic flux leakage
CVN	Charpy V-notch full-size-equivalent upper shelf energy, ft lb
DIMP	Distribution Integrity Management Program
DC-ERW	electric resistance welded pipe made with direct current
DSAW	double submerged-arc welded pipe
ECDA	external corrosion direct assessment
ERW	electric resistance welded pipe
FERC	Federal Energy Regulatory Commission
FFS	Fitness for service
HCA	high consequence area
HDB	hydrostatic design basis in conjunction with polyethylene pipe
HF-ERW	electric resistance welded pipe made with high frequency current (e.g., 450 KHz)
HSC	hydrogen stress cracking
HVL	highly volatile liquid
Hz	hertz (a unit of frequency equivalent to one cycle per second)
ICDA	internal corrosion direct assessment

INGAA	Interstate Natural Gas Association of America
ILI	in-line inspection
KHz	kilohertz (a unit of frequency equivalent to 1,000 cycles per second)
LF-ERW	electric resistance welded pipe made with low frequency current (by definition in API Specification 5L, a frequency less than or equal to 70 KHz. Commonly, 120 Hz was used in making older LF-ERW materials.)
MAOP	maximum allowable operating pressure (usually associated with a natural gas transmission pipeline or a natural gas distribution system)
MFL	magnetic flux leakage
MOP	maximum operating pressure (usually associated with a hazardous liquid pipeline)
NAEC	Narrow axial external corrosion
NDE	Non-destructive examination
NTSB	National Transportation Safety Board
PCIF	pressure-cycle-induced fatigue
PE	polyethylene
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIR	Potential impact radius as defined in 49 CFR 192.903
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
SCCDA	stress corrosion cracking direct assessment
SMYS	specified minimum yield strength
SSAW	single submerged-arc welded pipe
SSWC	selective seam weld corrosion

DEFINITIONS

General Terms Used in These Guidelines

Grandfathered

"Grandfathered" is a term associated with natural gas transmission pipelines. It refers to a pipe segment installed before July 1, 1970 with an MAOP established in accordance with 49 CFR § 192.619(c).

High Consequence Area (HCA)

A High Consequence Area (HCA) with respect to a natural gas transmission pipeline is defined in 49 CFR § 192.903. A High Consequence Area (HCA) with respect to a hazardous liquid pipeline is defined in 49 CFR § 195.452.

Legacy Pipe

Legacy pipe means steel pipe manufactured using any now-obsolete technique including furnace butt-welded, furnace lap-welded, low-frequency-welded electric resistance welded (LF-ERW), direct-current-welded electric resistance welded (DC-ERW), single submerged-arc welded (SSAW), or Flash Welded (A.O. Smith) pipe or any pipe with an unknown type of longitudinal seam. Legacy pipe also includes wrought iron pipe, pipe made from Bessemer steel, pipe of unknown specification or pipe for which the yield strength is unknown, and any pipe made prior to 1942 when the minimum levels of API-required manufacturers' pressure tests were raised significantly. Lastly, legacy pipe includes polyethylene (PE) plastic pipe materials that have a history of premature failures from slow crack growth.

Legacy Construction Techniques and Legacy Repair Methods

Legacy construction techniques refer to obsolete and potentially problematic construction techniques such as wrinkle bends in pipelines operated at stress levels equal to or exceeding 30% of SMYS, miter bends having included angles greater than 3 degrees in pipelines operated at stress levels equal to or exceeding 30% of SMYS, Dresser Couplings, threaded collars, non-standard fittings, oxyacetylene welds in cross-country transmission pipelines, and bell and spigot joints. Repair methods such as welded patches, half-soles and puddle welds constitute legacy repair methods that are, for the most part, no longer used.

Modern Pipe

Modern pipe refers to all pipe that is not legacy pipe.

Skelp

Iron or steel rolled or forged into narrow strips and ready to be made into pipe by being bent and welded.

49 CFR 192.3 Definitions Applicable to These Guidelines

Distribution line means a pipeline other than a gathering or transmission line.

Gathering line means a pipeline that transports gas from a current production facility to a transmission line or main.

High-pressure distribution system means a distribution system in which the gas pressure in the main is higher than the pressure provided to the customer.

Low-pressure distribution system means a distribution system in which the gas pressure in the main is substantially the same as the pressure provided to the customer.

Main means a distribution line that serves as a common source of supply for more than one service line.

Maximum actual operating pressure means the maximum pressure that occurs during normal operations over a period of 1 year.

Maximum allowable operating pressure (MAOP) means the maximum pressure at which a pipeline or segment of a pipeline may be operated under this part.

Operator means a person who engages in the transportation of gas.

Service line means a distribution line that transports gas from a common source of supply to an individual customer, to two adjacent or adjoining residential or small commercial customers, or to multiple residential or small commercial customers served through a meter header or manifold. A service line ends at the outlet of the customer meter or at the connection to a customer's piping, whichever is further downstream, or at the connection to customer piping if there is no meter.

Transmission line means a pipeline, other than a gathering line, that: (1) Transports gas from a gathering line or storage facility to a distribution center, storage facility, or large volume customer that is not down-stream from a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS; or (3) transports gas within a storage field.

49 CFR 195.2 Definitions Applicable to These Guidelines

Hazardous liquid means petroleum, petroleum products, or anhydrous ammonia.

Highly volatile liquid or *HVL* means a hazardous liquid which will form a vapor cloud when released to the atmosphere and which has a vapor pressure exceeding 276 kPa (40 psia) at 37.8 °C (100 °F).

Low-stress pipeline means a hazardous liquid pipeline that is operated in its entirety at a stress level of 20 percent or less of the specified minimum yield strength of the line pipe.

Maximum operating pressure (MOP) means the maximum pressure at which a pipeline or segment of a pipeline may be normally operated under this part.

Operator means a person who owns or operates pipeline facilities.

Petroleum means crude oil, condensate, natural gasoline, natural gas liquids, and liquefied petroleum gas.

Petroleum product means flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.

Stress level means the level of tangential or hoop stress, usually expressed as a percentage of specified minimum yield strength.

Supervisory Control and Data Acquisition (SCADA) system means a computer-based system or systems used by a controller in a control room that collects and displays information about a pipeline facility and may have the ability to send commands back to the pipeline facility.

Surge pressure means pressure produced by a change in velocity of the moving stream that results from shutting down a pump station or pumping unit, closure of a valve, or any other blockage of the moving stream.

FACTORS TO CONSIDER IN MAKING REPAIR/REPLACE DECISIONS

The technical (non-economic) and integrity factors to consider when contemplating making a repair/replace decision are discussed in the following paragraphs. It will be seen that these factors overlap significantly those needed to manage pipeline integrity for hazardous liquid pipelines and natural gas transmission pipelines in high consequence areas (HCAs). In fact, replacement may become a rational choice if the continuing cost of managing integrity for an older pipeline or system becomes too high in comparison to the cost of replacement. The factors to consider include threats to pipeline integrity, the physical attributes of the pipeline or system, the operating history (pressure and pressure cycles, leak history, pressure test history,

in-line inspection (ILI) inspection history), and the circumstances (conditions) of a given pipeline segment (piggability, testabililty, operating stress, existence of legacy pipe, existence of legacy construction features). These groups of factors are discussed below.

Threats to Pipeline Integrity that Could Influence a Repair/Replace Decision

Experience has shown that certain threats may lead to pipeline leaks or ruptures. PHMSA requires pipeline operators to submit data on "reportable" incidents. The incidents are categorized by cause, and the causes correspond to threats to pipeline integrity. The PHMSA website http://primis.phmsa.dot.gov/comm/reports/safety/AllPSIDet_2004_2013_US.html presents a summary of reportable incidents as well as the detailed databases of incidents. In abbreviated form the PHMSA data for 2004 through 2013 are presented in Table 1.

Table 1. Summary of Reportable Incidents by Category for the Period 2004 through 2013

CAUSE OR THREAT	HAZARDOUS LIQUID	NATURAL GAS TRANSMISSION	NATURAL GAS DISTRIBUTION
CORROSION	22%	20%	2%
EXCAVATION DAMAGE	5%	15%	30%
INCORRECT OPERATION	11%	3%	4%
MAT'L/WELD/FAILURE	11%	14%	5%
EQUIPMENT FAILURE	37%	15%	3%
NATURAL FORCE DAMAGE	5%	14%	8%
OTHER OUTSIDE FORCE DAMAGE	2%	9%	33%
ALL OTHER CAUSES	5%	10%	15%
Totals	100%	100%	100%

A more detailed breakdown is given in Appendix B. The main things these data show are that the percentages of incidents by cause were different for hazardous liquid pipelines, natural gas transmission pipelines, and natural gas distribution systems. Corrosion was a significant cause of failure for hazardous liquid pipelines and natural gas transmission pipelines but not for natural gas distribution pipelines. Equipment failure accounted for the largest percentage of failures in hazardous liquid pipelines, a moderate percentage of failures for natural gas transmission pipelines, but only a small percentage of failures in natural gas distribution systems. The largest percentages of failures in natural gas distribution systems were caused by

other outside force damage and excavation damage whereas only small to moderate percentages of failures of hazardous liquid pipelines and natural gas transmission pipelines were attributed to these causes[3]. Stakeholders in pipeline safety (i.e., pipeline operators, regulators, and the general public) expect that operators of these systems will pursue mitigative responses to minimize or prevent the recurrence of these various types of incidents. As discussed below pipeline operators are required by federal regulations to address the prevention of incidents by developing and executing pipeline integrity management plans. It is noted, however, that pipeline replacement is rarely the most effective response to reducing pipeline incidents. Instead, a replacement decision is likely to be considered if and only if threat management is not feasible by other means.

Pipeline operators are required by federal regulations to identify and mitigate pipeline integrity threats via an integrity management plan. For gas distribution lines, these threats are managed under the operator's DIMP program. Integrity management plans embody periodic integrity assessment activities. In most cases repairs made in response to these integrity assessments will be an effective means to achieve reductions in incidents. In the development of guidelines for repair/replace decisions, the essential goal is to be able to determine for a particular pipeline segment whether or not all relevant threats can be successfully mitigated via periodic integrity assessments via the "repair" option. If it is not technically feasible to successfully mitigate one or more integrity threats via periodic integrity assessment, then it may be necessary to exercise the "replace" option. Threats to pipeline or system integrity are described in industry consensus standards and/or federal regulations.

Hazardous Liquid Pipelines

As outlined in API RP 1160 *Managing Systems Integrity for Hazardous Liquid Pipelines*, 2nd Edition, 2013, Chapter 4, hazardous liquid pipelines are thought to be exposed to the following integrity threats.

1) External corrosion

2) Internal corrosion

3) Selective seam weld corrosion (external or internal)

[3] The relatively low rates of failure from excavation damage attributed to hazardous liquid pipelines and natural gas transmission pipelines are believed to be the result of a focus over the last 20 years or so by pipeline operators, other utility operators, government regulators, and excavators on preventing such damage. Near-universal adoption of "one-call" network systems including the 811 phone number, enhanced communication between pipeline operators and excavators, and the development of public awareness programs by pipeline operators no doubt have contributed to a significant reduction in excavation damage accidents. Operators of gas distribution systems, as well, have adopted these improved practices. However, the fact that distribution piping is located in areas of high exposure to damage tends to explain why these systems exhibited a higher rate of incidents.

4) Stress corrosion cracking (SCC)

5) Manufacturing defects (defective pipe seams including hard heat-affected zones and defective pipe including pipe body hard spots[4])

6) Construction and fabrication defects (including defective girth welds, defective fabrication welds, wrinkle bends and buckles, and stripped threads/broken coupling failures)

7) Equipment failure (including gasket or O-ring failure, control/relief equipment failure, seal/pump packing failure, and miscellaneous)

8) Mechanical damage (causing an immediate failure or from vandalism)

9) Mechanical damage (previously damaged pipe or vandalism causing a delayed failure)

10) Incorrect operations

11) Weather and outside force (cold weather, lightning, heavy rains or floods, and earth movement)

12) The growth of an initially non-injurious anomaly arising from any one of several of the above causes into an injurious defect via pressure-cycle-induced fatigue (including transit fatigue)

In terms of guidelines for repair/replace decisions, any systematic threat that affects an entire segment such as bare pipe could make the segment a candidate for replacement. In addition threats that could affect locations at random along buried segments of a pipeline could also become a reason for replacement because of the efforts required to detect and repair the affected locations and to mitigate future occurrences of incidents attributable to certain causes. External corrosion, internal corrosion, SCC, selective seam weld corrosion, manufacturing defects (which tend to become threats as the result of pressure-cycle-induced fatigue (PCIF)), and construction and fabrication defects constitute threats that could lead to a decision to replace a segment rather than to repair it. At the other extreme, threats arising from the potential for equipment failure and incorrect operations can be mitigated by means of regular

[4] Hard-heat affected zones and pipe body hard spots are confined to specific vintages of pipe made by specific manufacturers. While these phenomena are not wide spread, the can cause failures and may constitute a reason for replacing a pipeline segment. One segment of these guidelines is dedicated to discussing the nature of this threat and the means by which it may be mitigated is discussed in another segment.

maintenance and training programs and, therefore, would not be expected to lead to replacement of a pipeline segment.

From the standpoint of immediate failure from mechanical damage, incidents seem to be declining in numbers with time because of increased focus on damage prevention (e.g., better one-call systems, mandated damage prevention programs, improved state one-call laws). Therefore, it seems unlikely that a hazardous liquid pipeline segment would require replacement to mitigate immediate failures from mechanical damage. Moreover, to the extent the threat exists, the replacement segment could be just as exposed as the original segment although the new pipe could be made more resistant to damage by increased wall thickness, deeper burial, and/or installing a passive or active warning system.

It seems unlikely that replacement of a segment would be a practical means of mitigating the threat of delayed failure from mechanical damage. Such damage is not likely to be as wide-spread as damage from the threats of corrosion, SCC, and manufacturing and construction defects. Besides, it is relatively easy to locate and repair such damage using an appropriate ILI technology.

The threat of weather and outside force incidents falls into a special repair/replace decision category. The areas along a pipeline most likely to be affected by heavy rains/flood are at river crossings. In some cases it might be necessary to replace a river crossing to decrease its exposure to damage from flooding. Similarly, areas of earth movement are generally easy to identify such that a local replacement of pipe could be a rational mitigative response. There is no expectation that replacement of a pipe segment would be a rational mitigative response to the threat of cold weather or lightning.

Natural Gas Transmission Pipelines

As outlined in ASME B31.8S – 2012 Managing System Integrity of Gas Pipelines, Chapter 2, natural gas transmission pipelines are thought to be exposed to the following integrity threats.

(a) Time-Dependent

1. External corrosion
2. Internal corrosion
3. Stress corrosion cracking (SCC)

(b) Stable

1. Manufacturing-related defects

a. Defective pipe seam

b. Defective pipe

2. Welding/fabrication related

a. Defective pipe girth weld (circumferential) including branch and T joints

b. Defective fabrication weld

c. Stripped threads/broken pipe/coupling failure

3. Equipment

a. Gasket, O-ring failure

b. Control/relief equipment malfunction

c. Seal/pump packing failure

d. miscellaneous

(c) Time-Independent

1. Third party/mechanical damage

a. Damage inflicted by first, second, or third parties (immediate failure)

b. Previously damaged pipe (such as dents and/or gouges)(delayed failure)

c. vandalism

2. Incorrect operational procedure

3. Weather-related and outside force

a. Cold weather

b. Lightning

c. Heavy rains or floods

d. Earth movements

The presumed threats to natural gas transmission pipelines are nearly identical to those that are thought to affect hazardous liquid pipelines. The main difference is that manufacturing and welding/fabrication defects in gas pipelines are considered stable defects whereas such defects are considered to be susceptible to growth from pressure-cycle-induced fatigue in a hazardous liquid pipeline. In most cases the assumption of stability of such defects in gas service is justified because the pressure-cycle intensity in a typical gas pipeline is much less than that associated with a typical hazardous liquid pipeline. It should be noted, however, that the assumption of stability of manufacturing and welding/fabrication defects in gas pipelines may not always be valid. Such defects are rendered stable, if and only if, a prior hydrostatic test or pneumatic pressure test has been conducted to establish a satisfactory margin between test pressure and operating pressure. Moreover, other factors such as changes in operations and/or changes in the operating environment could have an adverse effect on stability. It is prudent for a gas pipeline operator to at least evaluate the effects of pressure cycles for their pipelines in the context of prior test pressures, possible changes in operating pressures, and changes in the operating environment to be sure that the assumption of stability is justified.

For natural gas transmission pipelines, the threats of external corrosion, internal corrosion, selective seam weld corrosion (SSWC), and SCC constitute threats that could lead to a decision to replace a segment rather than to repair it. In addition, the existence of features such as miter bends and wrinkle bends in pipelines that are operated at stress levels of 30% of SMYS or more, non-standard fittings, Dresser couplings, and acetylene girth welds (legacy construction techniques) need to be considered in the context of making repair/replace decisions.

As discussed previously in conjunction with threats to hazardous liquid pipelines, it is likely that replacement will not constitute a reasonable response to the threat of immediate mechanical damage or the threat of delayed failure from prior mechanical damage. Similarly, threats arising from the potential for equipment failure and incorrect operations can be mitigated by means of regular maintenance and training programs and, therefore, would not be expected to lead to replacement of a pipeline segment.

The threat of weather and outside force incidents with respect to making repair/replace decisions is the same for a gas transmission pipeline as discussed previously in conjunction with hazardous liquid pipelines. In some cases it might be necessary to replace a river crossing to decrease its exposure to damage from flooding. Similarly, replacement of pipe could be a rational mitigative response in areas of earth movement. There is no expectation that replacement of a pipe segment would be a rational mitigative response to the threat of cold weather or lightning.

A final point relevant to repair/replace decision-making with respect to natural gas transmission pipelines is that, unlike in the case of a hazardous liquid pipeline, small leaks in a gas pipeline

can be repaired and are generally not hazardous to people, property, or the environment. Thus, whereas a hazardous liquid pipeline that is prone to develop small leaks repeatedly from a cause that is hard to control might be a candidate for replacement, replacement of a gas pipeline that repeatedly developed small leaks might not be the most appropriate response.

Pipe Body Hard Spots and Hard Heat-Affected Zones

This discussion concerns a threat to the integrity of pipelines, both liquid and gas, that is unique to a certain vintage of line pipe materials if those materials had been accidentally quenched from a hot-working temperature to room temperature because of an upset in the manufacturing process. The threat is hydrogen stress cracking (HSC). It is discussed separately from the other threats, not because it is a common cause of failure (it is not), but because if the threat exists in a given pipeline, unique methods must be used to control the phenomenon.

From the late 1940s until about 1960, high-yield-strength line pipe materials (API 5L Grades X42 through X52) tended to rely heavily on carbon and manganese contents[5] higher than typically used to produce the lower-yield-strength Grade A and Grade B line pipe materials commonly used prior to the late 1940s. As a result, the "X-grade" materials tended to be highly hardenable if quenched rapidly to room temperature from the hot-rolling temperature range or if allowed to cool too quickly after being welded. An X-Grade material of this vintage cooled too quickly could end up having an untempered martensite microstructure, a very hard material (35 Rockwell C or more), that is susceptible to HSC if subjected to a high-enough stress level in the presence of atomic hydrogen. The operating hoop stress levels in many pipelines constitute sufficient stress, and the atomic hydrogen can be generated at areas of damaged coating by cathodic protection current.

In the normal production of line pipe skelp in the period from 1947 through 1960, hot-rolled plates or coils underwent controlled cooling to room temperature so that the microstructure achieved (pearlite-ferrite) was not susceptible to HSC. During welding processes, the cooling rate could also be controlled to prevent rapid quenching by means of preheating, by controlling inter-pass temperatures, or by post-weld heat treatment. The latter, post-weld heat treatment, was often employed after the making of line pipe with an ERW longitudinal seam to prevent excessive hardness. By 1960 most line pipe producers had switched to micro-alloyed skelp where elements such as vanadium or columbium were used in small quantities in place of excessive amounts of carbon and manganese to achieve the high strength levels characteristic

[5] Carbon contents of some (not all) heats could range as high as 0.29 to 0.34 percent by weight and manganese contents could exceed 1.0 percent by weight. Materials that had both carbon and manganese contents within these ranges tended to be easily hardenable.

of X-Grade materials. With advent of the use of micro-alloyed materials, the potential for encountering high hardness levels from a too-high cooling rate was greatly reduced.

The threat of HSC in pipelines (gas or liquid) made from these vintage materials can arise if areas of the skelp were accidentally quenched at the end of the hot-rolling process or if an ERW seam made in such a material was given inadequate post-weld heat treatment. One of the best references on the HSC phenomenon is a paper by Groeneveld[ii] in 1974. This paper explains the phenomenon and indicates that HSC had accounted for several pipeline failures. The paper also discusses steps that pipeline operators may take to mitigate the threat of failures from HSC. Some of these mitigating measures turned out to be practical, and they are discussed later in these guidelines.

Natural Gas Distribution Systems

Repair/replacement decisions as well as integrity management[6] for natural gas distribution systems involve consideration of threats that differ substantially from those associated with repair/replacement decisions in a hazardous liquid pipeline or a natural gas transmission system. The reason for the difference is largely due to the following circumstances: 1) axial rupture (which is a common mode of failure in hazardous liquid and gas transmission pipelines) is an unlikely mode of failure in a gas main or service because of the low operating stress levels of distribution systems (below 20% SMYS), 2) over 50% of the mileage of distribution systems nationwide is comprised of polyethylene pipe (a material that is not commonly used in a gas or liquid transmission system), 3) cast iron pipe still comprises more than 2% of the gas mains in the nationwide distribution network whereas none is found in a gas or liquid transmission pipeline, 4) the methods often used to assess the integrity of hazardous liquid pipelines and natural gas transmission pipelines (hydrostatic testing and ILI) are seldom applicable to natural gas distribution systems (where leak surveying is a more common method.) The distribution industry also uses trenchless pipe replacement methods such as slip-lining, pipe insertion, or pipe bursting that allows replacement of pipe segments without requiring full exposure of the pipe.

In 2011 the data from annual reports required by PHMSA[iii] showed the following distribution of materials in the nationwide network of mains and services.

[6] As noted previously, with the promulgation of 49 CFR 192, Subpart P, "Gas Distribution Integrity Management" in 2009, operators of gas distribution systems must establish a Distribution Integrity Management Program (DIMP) that covers all parts of each distribution system.

Table 2. Miles of Mains by Material in 2011

Steel Main Mileage	552,407	44.80%
Plastic Main Mileage	645,252	52.33%
Cast Iron Main Mileage	33,624	2.73%
Ductile Iron Main Mileage	751	0.06%
Copper Main Mileage	30	0.00%
Other Main Mileage	893	0.07%
Total	1,232,955	

Table 3. Numbers of Services by Material in 2011

Number of Steel Services	19,411,684	29.22%
Number of Plastic Services	44,273,373	66.64%
Number of Cast Iron Services	14,908	0.02%
Number of Ductile Iron Services	726	0.00%
Number of Copper Services	1,054,804	1.59%
Number of Other Services	1,677,778	2.53%
Total	66,433,273	

According to the Code of Federal Regulation 49 CFR §192.1007(b) distribution system operators must consider the following integrity threats.

1) Corrosion
2) Natural forces
3) Excavation damage
4) Other outside force damage
5) Material or welds
6) Equipment failure
7) Incorrect operations
8) Other concerns that could threaten the integrity of the pipeline

These threats correspond to the major categories of accidents shown in Table 1, but determining the bases for repair/replace decisions requires consideration of more detailed analysis of these threats. As one can see from the detailed incident data in Appendix B, neither external nor internal corrosion has been a significant cause of incidents affecting natural gas

distribution systems. There are several reasons for this. First, more than 50% of the natural gas distribution piping is comprised of plastic pipe that is not subject to corrosion. Second, internal corrosion is unlikely because most of the corrosive components of natural gas have been removed before the gas is received by a distribution system. Third, about 86% of the steel mains are coated and cathodically protected (based on the 2011 annual reports mentioned previously). Nevertheless, there could be some steel mains and services, particularly those that have no external coating and are not subject to cathodic protection, that should be considered for replacement due to on-going corrosion that cannot be readily mitigated.

The threat of natural forces, (i.e., heavy rains/floods, earth movement, temperature, and lightning) can be a significant factor in a repair/replace decision for a gas distribution system, particularly a system containing cast iron mains and/or services. In some cases it might be necessary to replace a segment of cast iron pipe if it is susceptible to damage from flooding. Similarly, replacement of cast iron pipe could be a rational mitigative response in areas of earth movement. The threat of cast iron, coupled pipe, or pipe joined by threaded connections being damaged by frost heave or any situation resulting in soil subsidence exists particularly if the pipe is not properly supported or protected. Therefore, the situation where a segment is installed in soil that is prone to frost heave or other soil subsidence could influence a repair/replace decision for a cast iron or threaded-joint segment. There is no expectation that replacement of a pipe segment would be a rational mitigative response to the threat of lightning.

There likely could be instances where repair/replace decisions will arise from the threat of material/weld failures. The relatively low operating stress levels of steel pipe in natural gas distribution systems (hoop stress levels of less than 20% of SMYS) eliminate the threats of SCC and PCIF that can affect steel pipe in high-pressure transmission pipelines. However, in spite of the relatively low operating stress levels, plastic, cast iron, and steel mains and services can be susceptible to failure, and the threat of systematic failures could be a basis for deciding to replace pipe instead of repairing it. Specifically, some older grades of plastic pipe may be susceptible to the phenomenon of "slow crack growth"[iv]. Cast iron pipe is quite brittle and is known to be susceptible to breakage from earth movement, washouts, and weakening from "graphitization"[v]. Bare steel mains or services without cathodic protection could be candidates for replacement. Steel pipe with an ERW seam that is susceptible to selective seam weld corrosion could be subject to rupture in spite of a low operating stress level. Systems affected by these phenomena could become candidates for a repair/replace decision.

Except for cast iron pipe, replacement of mains and services is generally not an appropriate response to the threats of excavation damage and other outside force damage. Cast iron is especially susceptible to any disturbances of nearby soil, so it is not unusual to consider replacement of cast iron pipe in conjunction with activities such as repaving streets or the

installation of a new underground facility, such as a sewer, nearby. In general, however, replacement of pipe is unlikely to reduce the threat of future excavation damage.

The threat of equipment failure is best addressed by an effective maintenance program, and the threat of failure from incorrect operations is best addressed by appropriate training of the operator's personnel and of contractors employed by the operator. So, these threats do not appear appropriate for repair/replace decision-making for a natural gas distribution system.

Attributes of Pipelines that Matter in Making a Repair/Replace Decision

Hazardous Liquid Pipelines

The 29 attributes which are useful for making repair/replace decisions for a hypothetical example of a hazardous liquid pipeline are shown in Table 4. Suggested remedies are given in Column 4 of the table for determining an attribute when that attribute is not initially known.

Table 4. Example of Attributes of a Hazardous Liquid Pipeline

Attribute Number	Attribute	Example Value	Remedy if Unknown and Essential
1	Diameter, inches	16	Measure at selected sites or globally via a caliper tool.
2	Maximum Operating Pressure, psig	1170	Calculate using SMYS, diameter, wall thickness, design factor, and joint factor.
3	Wall Thickness, inch	0.25	Measure globally using a UT wall thickness ILI tool or see 49 CFR 195.106(c)
4	Maximum Operating Stress, %SMYS	72	This quantity is based on the design factor (see below)
5	Transported Product	Crude Oil	This quantity is fixed by the operator's FERC certificate.
6	Material Specification	APL 5L	
7	Grade	X52	
8	SMYS, psi	52,000	use 24,000 psi or see 49 CFR 195.106(b)
9	Manufacturing Process (seam type)	LF-ERW	See "History of Line Pipe Manufacturing in North America" or determine via metallography
10	Joint Factor	1	See 49 CFR 195.106(e)
11	Year Pipe Manufactured	1953	
12	Fracture	96	Values can be determined by

Attribute Number	Attribute	Example Value	Remedy if Unknown and Essential
	Toughness, ksi√in		testing samples
13	Transition Temperature, ºF	80	Values can be determined by testing samples
14	Design Factor	0.72	See 49 CFR 195.106(a).
15	Year Installed	1953	
16	Length of Pipeline, miles	900	This quantity is chosen by the designer.
17	Length of HCA Segments, miles	200	This quantity is determined by the operator in compliance with 49 CFR 195.452
18	Miles of Legacy Pipe	900	
19	Electric-arc Girth Welds	120,000	Can be determined by pigging if piggable.
20	Acetylene Girth Welds	0	Can be determined by pigging if piggable.
21	Miter Bends	0	Can be determined by pigging if piggable.
22	Wrinkle Bends	0	Can be determined by pigging if piggable.
23	Mechanical Couplings	0	Can be determined by pigging if piggable.
24	Threaded Collars	0	Can be determined by pigging if piggable.
25	Bell and Spigot Joints	0	Can be determined by pigging if piggable.
26	Locations of Valves, Fittings, and Appurtenances	Provided in a list	Can be determined by pigging if piggable.
27	Coating Type	Coal tar enamel with felt wrap	Can be established through direct examination
28	Type of Cathodic Protection	Impressed current	Can be established through direct examination
29	Leak Detection System	volume balance plus aerial patrol	This leak detection system is chosen by the operator

The attributes listed in Table 4 are important for making repair/replace decisions because they are needed to assess the ability of a pipeline to be operated safely with minimal risk of leaks or ruptures. Methods for calculating failure stresses and remaining lives of defects depend on the

pipe geometry (diameter and wall thickness), pipe material properties (yield strength, ultimate tensile strength, fracture toughness, transition temperature[7]), and maximum operating stress. The type of longitudinal seam must be known to determine the amount of legacy pipe in the system. The mileage of HCAs is helpful in assessing the consequences of failures. The types and locations of circumferential joints should be known in order to assess the risk of failures from external forces such as earth movement and heavy rains/floods. The locations of valves, fittings, and appurtenances should be known to facilitate the use of ILI. The type of coating and type of cathodic protection are useful in determining the risk of failures from corrosion and SCC. Knowing the type of fluid in the pipeline and the type of leak detection system can be helpful in assessing the consequences of leaks and ruptures. It is essential to know when the pipe was manufactured in order to determine whether or not the pipe is legacy pipe simply because of its age. Lastly, miter bends (misalignments at circumferential joints with more than 3 degrees of angle change) and wrinkle bends are not permitted in hazardous liquid pipelines

Natural Gas Transmission Pipelines

The 48 attributes which are useful for making repair/replace decisions for a hypothetical example of a natural gas transmission pipeline are shown in Table 5. Because of the existence of class locations in gas pipelines, the number of attributes is considerably higher than the number associated with hazardous liquid pipelines. Suggested remedies are given in Column 4 of the table for determining an essential attribute when that attribute is not initially known.

As was the case for hazardous liquid pipelines, the attributes listed in Table 5 are important for making repair/replace decisions because they are needed to assess the ability of a pipeline to be operated safely with minimal risk of leaks or ruptures. Methods for calculating failure stresses and remaining lives of defects depend on the pipe geometry (diameter and wall thickness), pipe material properties (yield strength, ultimate tensile strength, fracture toughness, transition temperature), and maximum operating stress. The type of longitudinal seam, grade, and era of manufacture must be known to determine the amount of legacy pipe in the system. The mileage of HCAs is helpful in assessing the consequences of failures. The types and locations of circumferential joints should be known in order to assess the risk of failures from external forces such as earth movement and heavy rains/floods. The locations of

[7] Whereas §195.106(b) for liquid pipelines and §192.107 for gas pipelines give specific guidance for determining the yield strength of a pipe material of unknown yield strength, no such guidance exists for determining toughness and transition temperature. If an operator orders API 5L pipe to a certain toughness and/or transition temperature level, the number of such determinations would be one per heat or one per 100 joints depending on pipe size. An operator would need to make a similar number of determinations for an existing pipeline by cutting out and testing samples to ascertain a reliable value of base metal toughness and/or transition temperature. Because of the extreme variability of toughness in the bond line regions of LF-ERW, DC-ERW, and flash-welded pipe materials, it is doubtful that this number of determinations would be sufficient to ascertain the bond line toughness. For bond line toughnesses in such materials it is reasonable to assume that a defect in the bond line (e.g., a cold weld) will fail in a brittle manner and that the effective toughness will be less than or equal to a full-size-equivalent Charpy V-notch impact energy of 1 ft lb.

valves, fittings, and appurtenances should be known to facilitate the use of ILI. The type of coating and type of cathodic protection are useful in determining the risk of failures from corrosion and SCC. It is essential to know when the pipe was manufactured in order to determine whether or not the pipe is legacy pipe simply because of its age.

Table 5. Example of Attributes of a Natural Gas Transmission Pipeline

Attribute Number	Attribute	Example Value	Remedy if Unknown and Essential
1	Diameter, inches	30	Measure at selected sites or globally via a caliper tool.
2	MAOP, psig (Class 1 location)	936	Set by the requirements for throughput
3	MAOP, psig (Class 2 location)	936	Set by the requirements for throughput
4	MAOP, psig (Class 3 location)	936	Set by the requirements for throughput
5	MAOP, psig (Class 4 location)	936	Set by the requirements for throughput
6	Wall Thickness, inch (Class 1 location)	0.375	Measure using methods described in 49 CFR 192.109
7	Wall Thickness, inch (Class 2 location)	0.45	Measure using methods described in 49 CFR 192.109
8	Wall Thickness, inch (Class 3 location)	0.54	Measure using methods described in 49 CFR 192.109
9	Wall Thickness, inch (Class 4 location)	0.675	Measure using methods described in 49 CFR 192.109
10	Maximum Operating Stress, %SMYS (Class 1 location)	72	This quantity is based on the design factor (see below)
11	Maximum Operating Stress, %SMYS (Class 2 location)	60	This quantity is based on the design factor (see below)
12	Maximum Operating Stress, %SMYS (Class 3 location)	50	This quantity is based on the design factor (see below)
13	Maximum Operating Stress, %SMYS (Class 4 location)	40	This quantity is based on the design factor (see below)

Table 5 (continued). Example of Attributes of a Natural Gas Transmission Pipeline

Attribute Number	Attribute	Example Value	Remedy if Unknown and Essential
14	Transported Product	Natural Gas	This quantity is fixed by the operator's FERC certificate.
15	Material Specification	APL 5L	
16	Fracture Toughness, ksi√in	96	Values can be determined by testing samples
17	Transition Temperature, ºF	110	Values can be determined by testing samples
18	Grade	X52	
19	SMYS, psi	52,000	use 24,000 psi or see 49 CFR 192.107
20	Manufacturing Process (seam type)	Flash-welded	See "History of Line Pipe Manufacturing in North America" or determine via metallography
21	Joint Factor	1	See 49 CFR 192.113
22	Temperature Derating Factor	1	See 49 CFR 192.115. This factor is 1 if the segment is operated at a temperature of 250□F (121□C) or less.
25	Year Pipe Manufactured	1960	
26	Design Factor (Class 1 location)	0.72	See 49 CFR 192.111.
27	Design Factor (Class 2 location)	0.6	See 49 CFR 192.111.
28	Design Factor (Class 3 location)	0.5	See 49 CFR 192.111.
29	Design Factor (Class 4 location)	0.4	See 49 CFR 192.111.
30	Year Installed	1960	
31	Length of Pipeline, miles	1000	This quantity is established by the designer.
32	Length of Class 1 Segments	800	The locations of each class location and the mileage is determined by the operator in compliance with 49 CFR 192.5
33	Length of Class 2 Segments	150	The locations of each class location and the mileage is determined by the operator in compliance with 49 CFR 192.6

Table 5 (concluded). Example of Attributes of a Natural Gas Transmission Pipeline

Attribute Number	Attribute	Example Value	Remedy if Unknown and Essential
34	Length of Class 3 Segments	50	The locations of each class location and the mileage is determined by the operator in compliance with 49 CFR 192.7
35	Length of Class 4 Segments	0	The locations of each class location and the mileage is determined by the operator in compliance with 49 CFR 192.8
36	Length of HCA Segments, miles	200	This quantity is determined by the operator in compliance with 49 CFR 192.903
37	Length of OCA Segments, miles	200	This quantity is determined by the operator
38	Miles of Legacy Pipe	0	
39	Electric-arc Girth Welds	132,000	Can be determined by pigging if piggable.
40	Acetylene Girth Welds	0	Can be determined by pigging if piggable.
41	Miter Bends	0	Can be determined by pigging if piggable.
42	Wrinkle Bends	0	Can be determined by pigging if piggable.
43	Mechanical Couplings	0	Can be determined by pigging if piggable.
44	Threaded Collars	0	Can be determined by pigging if piggable.
45	Bell and Spigot Joints	0	Can be determined by pigging if piggable.
46	Locations of valves, fittings, and appurtenances	Provided in a list	Can be determined by pigging if piggable.
47	Coating Type	Coal tar enamel with felt wrap	Can be established through direct examination
48	Type of Cathodic Protection	Impressed current	Can be established through direct examination

Note that miter bends (misalignments at circumferential joints with more than 3 degrees of angle change) are not permitted in natural gas pipelines that are operated at hoop stress levels of 30% of SMYS or more. Miter bends with angle changes not exceeding 12.5 degrees are permitted if the pipeline is operated at a hoop stress level less than 30% of SMYS, miter bends with angle changes not exceeding 90 degrees are permitted if the pipeline is operated at a hoop stress level of 10% of SMYS or less. Wrinkle bends are permitted if the pipeline is operated at a hoop stress level less than 30% of SMYS.

Natural Gas Distribution Systems

Natural gas distribution systems are comprised of mains and services which are often parts of a complex interconnected (sometimes described as "reticulated") system designed to distribute gas from one or more transmission pipelines to industrial, commercial, and residential customers. Gas may flow in either direction in a main that is part of a complex network of mains. Services branch out from taps on the mains to provide gas to end users. While any new or replaced pipe installed in a distribution system must be subjected to a pre-service pressure test, the nature of the interconnected system and the inability to interrupt customers makes it very challenging to conduct subsequent integrity assessments of existing pipe via pressure tests. Moreover, the layout of typical distribution systems and the relatively low operating pressures of these systems make it very difficult to use on-stream ILI technologies for integrity assessments. These aspects of distribution systems and the fact that they are operated at hoop stress levels less than (in many cases, much less than) 20% of SMYS mean that the risks associated with their operation are significantly different from the risks that are associated with the operation of a hazardous liquid or a natural gas transmission pipeline. Unlike hazardous liquid pipelines and natural gas transmission pipelines, many of which are operated at relatively high pressure levels, failures from hoop stress resulting in axial crack propagation in a gas distribution system are generally not possible. Instead incidents associated with gas distribution systems that create hazards for people and property are generally related to leakage of gas and accumulation of gas within a closed area leading to fires and/or explosions. Accordingly, 49 CFR 192, Subpart P, "Gas Distribution Integrity Management" was developed to address the special circumstances of gas distribution systems. This regulation was finalized on December 4, 2009. Under this rule, operators of gas distribution systems must establish a Distribution Integrity Management Program (DIMP) that covers the entirety of each distribution system. Therefore, repair/replace guidelines for gas distribution systems must take into account the special circumstances of such systems.

Attributes of Steel Mains and Services

The attributes of steel mains and services that need to be considered in a repair/replace decision for a gas distribution system are summarized in Table 6. Leaks from steel mains or services most commonly arise from external corrosion, excavation damage, mechanical couplings, and damage from earth movement or heavy rains/floods. Therefore, pipe geometry, material strength, operating pressure, locations of appurtenances, the existence of legacy pipe or joining methods, and the coating and cathodic protection are the essential attributes.

Table 6. Example of Attributes of Steel Main or Service in a Natural Gas Distribution System

Attribute Number	Attribute	Example Value	Remedy if Unknown and Essential
1	Diameter, inches	4.5	Measure at selected locations.
2	Wall Thickness, inch	0.188	See 49 CFR 192.109
3	Design Pressure, psig	1805	See 49 CFR 192.105
4	MAOP, psig	150	Set by the requirements for throughput.
5	Grade of pipe	A	
6	SMYS, psi	30,000	use 24,000 psi or see 49 CFR 192.107
7	Type of Seam	LF-ERW	Metallurgical examination of selected pieces
8	Design Factor	0.72	Based on Class 3 (49 CFR 192.111)
9	Joint Factor	1.0	See 49 CFR 192.113
10	Length of Main or Service, miles	10	
11	Year installed	1942	
12	Feet of Legacy Pipe	52,800	
14	Electric-arc Girth Welds	2,640	
15	Acetylene Girth Welds	0	
16	Miter Bends	0	
17	Wrinkle Bends	0	
18	Mechanical Couplings	0	
19	Locations of Valves and Fittings	Provided in a list	
20	Locations of Service Taps if a Main	Provided in a list	
21	Coating Type	Uncoated	Can be established through direct examination
22	Type of Cathodic Protection	None	Can be established through direct examination

Attributes of Plastic Mains and Services

The attributes of plastic mains and services that need to be considered in a repair/replace decision are summarized in Table 7.

Table 7. Example of Attributes of Plastic Main or Service in a Natural Gas Distribution System

Attribute Number	Attribute	Example Value	Remedy if Unknown and Essential
1	Diameter, inches	2.375	Measure at selected locations.
2	Wall Thickness, inch	0.216	Measure at selected locations.
	Design Pressure, psig	80	See 49 CFR 192.121
3	MAOP, psig	60	See 49 CFR 192.619
4	Type of Pipe (PE, PVC, ABS, CAB, PA-11)	PE	May be readable on the pipe[8]
5	Specification	ASTM D2513	May be readable on the pipe[6]
6	Material Designation Code for PE	PE 2406	May be readable on the pipe[6]
7	Design Factor	0.32	See 49 CFR 192.121
8	Hydrostatic Design Basis (73°F), psi	1250	Approximately 200 times the last two digits in the Material Designation Code[6] (eg. PE34**08**; HDB = 200 x **08** = 1600
9	Maximum Operating Temperature, °F	100-140	
10	Manufacturer	Century Utilities Products, Inc.	May be readable on the pipe[6]
11	Length of Main or Service, miles	15	
12	Date installed	1976	May be readable on the pipe[6] Date of manufacture may also be "coded" in the lot number in the print line.
13	Method of Joining End-to-End	Butt heat-fusion for PE	Can be determined by examining selected joints
14	Locations of Valves and Fittings	Provided in a list	
15	Locations of Service Taps if a Main	Provided in a list	
16	Type of connection and support at the main if a service	Provide description	
17	Mechanical Couplings	0	

[8] This is required in the print line at the time of installation. Print lines may not be present or legible upon excavation at later dates.

Leaks from plastic mains or services most commonly arise from third-party excavation damage, and damage from earth movement or heavy rains/floods. Generally, these threats would not be cause for replacement of an entire main or service. However, some specific older PE plastic pipe materials such as PE 2306 (particularly low-ductile inner wall Aldyl A piping) and PE3306 may be susceptible to the phenomenon of premature slow crack growth failures when subject to stress concentrations or excessive internal pressure relative to the long-term failure pressure of the material. Descriptions of the slow crack growth phenomenon, failures from slow crack growth and the shortcomings of the early research on the long-term behavior of plastic pipe are described in Reference IV (a special report by the National Transportation Safety Board (NTSB) that was published in 1998). In addition, PHMSA has issued the following advisory bulletins on the subject slow crack growth in plastic pipe:

- ADB-99-01, Potential failures due to cracking of plastic pipe manufactured by Century Utility Products, Inc, September 1, 1999
- ADB-99-02, Potential failures due to cracking of plastic pipe in natural gas systems, October 1, 1999
- ADB-02-07, Notification of the Susceptibility to Premature Brittle-Like Cracking of Older Plastic Pipe; Notice; correction, December 3, 2002
- ADB-07-01, Updated Notification of the Susceptibility to Premature Brittle-like Cracking of Older Plastic Pipe, September 6, 2007

These advisory bulletins may be downloaded from the following website:
http://phmsa.dot.gov/pipeline/regs/advisory-bulletin

Widespread occurrences of failures from slow crack growth could be a reason for considering replacement of certain vintage(s) of PE plastic mains and services. From the standpoint of the occurrence of slow crack growth, it is essential to know the type and grade of PE plastic (Material Designation Code, e.g. PE2306), the pipe manufacturer, the date of manufacture, the operating pressure, the maximum environmental operating temperature, the hydrostatic design basis (HDB), the type of fusion joining method, and the locations of possible stress concentrations (particularly regions where excessive deformation may be induced by inadequate support at joints, appurtenances, couplings, rock impingement, excessive bending and connections of services to mains).

Attributes of Cast Iron Mains and Services

Federal regulations do not permit the installation of new mains or services comprised of cast iron because of inherent risks associated with the material. However, as of 2011, 33,624 miles of cast iron mains and 14,908 cast iron services were still in existence. Cast iron pipe is extremely brittle and has been known to fail circumferentially from stresses associated with earth movement or loss of support from flooding. Moreover, the typical bell and spigot joints in

cast iron systems have essentially no resistance to longitudinal forces, and they are prone to leakage if they have not been sealed subsequent to original construction[9]. Also, gray cast iron, the most common type, is susceptible to the phenomenon of "graphitization", a form of corrosion that removes iron, leaving only a weak matrix of carbon which is porous and easily damaged, resulting in leakage. It is assumed that most distribution system operators are trying to replace their cast iron mains and services on a time schedule that is based on risk assessment and economics considerations. In the meantime continued leak surveys in accordance with the Part 192 regulations (§ 192.723) and management in accordance with DIMP regulations accompanied by necessary repairs to cast iron mains and services will be necessary.

The attributes of cast iron mains and services that need to be considered in a repair/replace decision are summarized in Table 8. The attributes are based largely on a historical document produced by American Cast Iron Pipe Company[vi]. It is noted that this document discusses pipe that was made for water service because the dimension tables refer to "AWWA" (American Water Works Association) standards (probably AWWA Standard C101) and the working pressures are given in feet of head. However, it is assumed that the cast iron pipe described in the above-mentioned document was similar to or the same as the cast iron pipe that was used in gas service. Operators must manage the safety and integrity of their cast iron systems in accordance with the provisions of Part 192 and their respective DIMP Programs. In addition, PHMSA has issued the following alert notices and an advisory bulletin on cast iron pipe:

- ALN-91-02, (Relates to recommended timely removal from service of cast iron pipe that is constitutes a risk to public safety), October 11, 1991
- ALN-92-02, (Reminds operators that surveillance plans must include surveillance of cast iron to identify problems and take appropriate action concerning graphitization), January 26, 1992
- ADB-12-05, (urges owners and operators to conduct a comprehensive review of their cast iron distribution pipelines and replacement programs and accelerate pipeline repair, rehabilitation and replacement of high-risk pipelines, requests state agencies to consider enhancements to cast iron replacement plans and programs, and alerts owners and operators of the pipeline safety requirements for the investigation of failures), March 23, 2012

These alert notices and the advisory bulletin may be downloaded from the following website: http://phmsa.dot.gov/pipeline/regs/advisory-bulletin

[9] Cast iron systems were typically installed at a time when most distribution systems transported only manufactured gas. The moisture and oils inherent in the manufacturing of the gas tended to saturate the original joint packing, keeping the joints moist and leak-tight. With the advent of dry natural gas, the packing was prone to drying out leading to leakage. All joints on most cast iron systems had to be retrofitted with external or internal sealing devices.

Table 8. Example of Attributes of Cast Iron Main or Service in a Natural Gas Distribution System

Attribute Number	Attribute	Example Value	Remedy if Unknown and Essential
1	Type of Material	Class A	Assume as a worst case
2	Nominal Diameter, inches	4	Measure at selected locations
3	Barrel OD, inches	4.80	Measure at selected locations
4	Nominal Wall Thickness, inch	0.48	Measure at selected locations
5	Design pressure, psig	624	See AMERICAN Pipe Manual, Section 12
6	MAOP, psig	25	Set by the requirements for throughput.
7	Length of Pieces, feet	12	Can be determined by examining selected joints
8	Length of Main or Service, miles	9.5	
9	Support condition	On blocks with tamped backfill	Can be established by excavation
10	Year installed	1925	
11	Method of Joining End-to-End	Bell and Spigot Joints	Can be determined by examining selected joints
12	Type of Subsequent Joint Sealing	External	Can be determined by examining selected joints
13	Mechanical Couplings	0	
14	Bell and Spigot Joints	4,180	
15	Locations of Valves and Fittings	Provided in a list	
16	Number and Locations of Service Taps if a Main	Provided in a list	
17	Corrosivity of soil for cast iron graphitization	Susceptibility to graphitization	Determine from operator records (e.g., exposed pipe reports, repairs records, continuing surveillance reports, etc.)

Records that Matter in Making a Repair/Replace Decision

As pipeline operators who have developed integrity management plans know, the records associated with the design, construction, operation, and maintenance of a pipeline are useful, if not essential, to the identification of threats and the assessment of risk. The same types of records are useful if not essential for making repair/replace decisions.

Material Specifications

The pipeline operator must know the specification to which the pipe material was made (e.g., API 5L, ASTM A53, ASTM D2513, etc.). Such specifications certify the type of material (e.g., steel, wrought iron, cast iron, plastic), the manufacturing process (e.g., seamless, ERW, DSAW), the diameter, the wall thickness, and the specified minimum yield strength (SMYS) of the pipe (or hydrostatic design basis in the case of polyethylene pipe). The design formulas for determining the wall thickness for various types of pipe materials embody the quantities: diameter, design pressure, SMYS (or hydrostatic design basis in the case of polyethylene pipe), and the joint factor for the type of longitudinal seam in steel or wrought iron pipe.

Design Records

Whether or not an operator has the original design records, the following parameters need to be established for integrity management purposes and/or repair/replace decisions. The essential records are: the design pressure, the location of the pipeline, the diameter(s), the wall thickness(es), the grade(s) and type(s) of pipe (including the type(s) of seams), the types of field joints, and the types and locations of appurtenances and other features (such as miter bends, wrinkle bends, reducers, elbows, tees, flanges, scraper traps, valves, etc.). Alignment sheets showing the locations of some or all of these attributes are useful. An elevation profile of the pipeline is essential for planning hydrostatic tests, for mitigating possible internal corrosion, and for establishing proper operating conditions in the case of a hazardous liquid pipeline. It is helpful if the design records for a pipeline list the design code and edition that governed its design. Unfortunately this was not often the case for legacy pipelines, but it is a good idea for future pipelines. PHMSA issued an advisory bulletin (Verification of Records - ADB-12-06, dated May 7, 2012, Docket No. PHMSA–2012–0068) to pipeline operators concerning material and pressure test records needed to confirm pipeline MAOP/MOP.

Construction Records

Construction records should reveal the contractor involved, the dates of construction, and descriptions of the progress of the work. However, these documents are not essential to making a repair/replace decision, and no mitigative action is necessary if they cannot be located or do not exist.

What is useful and necessary for making a repair/replace decision is the actual as-built locations of appurtenances and other features that can influence the success of integrity verification and mitigative actions.

Welding Procedure and Welder Qualification

A welding procedure specification for girth welds and the welder and procedure qualification records are indicative of the quality of work associated with constructing a pipeline. However, these documents are not essential to making a repair/replace decision. No mitigative action is necessary if they cannot be located or do not exist.

Girth Weld Inspection Records

Girth weld inspection records at a minimum should describe the inspection procedure and present a list of the numbers of welds accepted and the number containing rejectable defects. The records of welds that did not pass but were repaired and not replaced entirely should also exist. These documents are useful but not essential for making a repair/replace decision. No mitigative action is necessary if they cannot be located or do not exist.

Pressure Test Records

Pressure tests are an essential means of establishing the fitness of a pipeline for service[10]. The initial pre-service test, if one was conducted, establishes the initial integrity of a pipeline or distribution main or service. Where time-dependent threats may have degraded a pipeline with the passage of time, a subsequent hydrostatic test or pneumatic pressure test will tend to indicate whether or not the degradation has been significant. Therefore, an operator who may be contemplating repair versus replacement of a given pipeline segment should review the results of all pressure tests that have ever been conducted on the segment. Such pressure test records can be extremely useful in determining whether or not continuing mitigation via hydrostatic testing is feasible as opposed to replacing the segment.

The following paragraphs list the current (2014) regulatory requirements for record keeping with respect to pressure testing. It is recognized that keeping pressure test records was not required prior to the advent of federal regulations (November 12, 1970). It is also noted that the requirements for record keeping have evolved since the regulatory requirements were first promulgated. Therefore, while the following listings are what is required currently, pipeline operators should not be expected to have all of these items for all historic tests. By far the most important records pertain to the pressure levels achieved in the most recent pressure test.

[10] As previously noted, it is recognized that distribution operators will generally not be able to conduct pressure tests of their infrastructure once the assets have been placed in service.

Requirements for Test Records for a Hazardous Liquid Pipeline

Section 195.310 of the 49 CFR 195 requires that the following records of each pressure test to be kept as long as the facility is in use.

- Pressure recording charts
- Test instrument calibration data
- The name of the pipeline operator
- The name of the person responsible for conducting the test
- The name of the test company used if not tested by the operator
- The time and date of the test
- The minimum test pressure
- The test medium
- A description of the facility tested and the test apparatus
- An explanation of any pressure discontinuities on the pressure recording charts, including test failures, that appear on the pressure recording charts
- A profile of the pipeline showing the elevation and test sites over the entire length of the test section where elevation differences in the section under test exceed 100 feet (30 meters)
- The temperature of the test medium during the test period (usually in the form of a temperature chart)

The test pressure for a hazardous liquid pipeline must be at least 125% of the MOP of the pipeline, and it must be held at or above that level for 4 hours. For buried segments where direct visual inspection for leaks is not possible, the pressure must be held an additional 4 hours at a level not less than 110% of the MOP. If hydrostatic testing is used periodically to validate the integrity of an existing pipeline for integrity management purposes or to keep from having to replace it, the operator may want to consider spike testing for a short time to a level significantly higher than 125% of MOP before completing the required 4-hour test at 125% of MOP.

Requirements for Test Records for a Natural Gas Transmission Pipeline or a Natural Gas Distribution Main or Service

Section 192.517 of the 49 CFR 192 requires that the following records of each pressure test be kept as long as the facility is in use unless the facility operates at a pressure level below 100

psig, the segment is a service line, or the segment is comprised of plastic pipe. Records for the latter three are to be kept for a minimum period of 5 years[11].

- The name of the pipeline operator
- The name of the person responsible for the test
- The name of the test company used if not tested by the operator
- The test medium used
- The test pressure
- The test duration
- Pressure recording charts, or other record of pressure readings
- Elevation variations, whenever significant for the particular test
- Leaks and failures and their disposition

Natural gas pipelines that are operated at stress levels of 30% of SMYS or more must be strength tested for a period of at least 8 hours. With some exceptions[12] the test must be a hydrostatic test to a minimum pressure level of 125% of MAOP for Class 1 and Class 2 locations and 150% of MAOP for Class 3 and Class 4 locations. If hydrostatic testing is to be used once or periodically to validate the integrity of an existing pipeline for integrity management purposes or to keep from having to replace it, the operator may want to consider spike testing for a short time to a level significantly higher than 125% of MAOP before completing the required 8-hour test.

Natural gas pipelines that are operated at stress levels of less than 30% of SMYS, steel services, and plastic pipe can be tested with water or pneumatically with natural gas, air, or inert gas. Except for the initial pre-service test of plastic pipe which is a minimum of 150% of MAOP (49 CFR 192.619), these tests are primarily for the purpose of establishing the absence of leakage and the MAOP. Leak-tightness could be a significant factor in a repair/replace decision. Therefore, the records on any leak tests could be useful for repair/replace decisions.

Pressure Test Failure Records

Besides the above-described records that are required by federal regulations in conjunction with a pressure test, the occurrences of test failures, the locations and elevations of test failures, the

[11] A prudent operator should keep material mechanical/chemical properties test reports and pressure test reports to document the pipeline MAOP for the life of the pipeline no matter what the minimum Code criteria say. These records are required for an integrity management program to comply with Part 192 or Part 195

[12] Class 1 locations may be tested with air or natural gas to a pressure level of 1.1 times MAOP except for locations within 300 feet of a building intended for human occupancy. In the latter locations the pipeline may be tested with air of inert gas, but the test pressure level must be at least 1.25 times MAOP for a distance of 300 feet upstream and downstream from the building. Air or Inert gas pressure testing is permitted in other class locations, but the pressure limits are such that the resulting MAOP will be less than the level one can validate via a hydrostatic test where the test pressure can be significantly higher.

failure pressures, and the causes of the failures should be assessed in making a repair/replace decision.

Operating Records

From the standpoint of making repair/replace decisions, an essential part of the operational history of a pipeline is its pressure history with the passage of time. Ideally, for a hazardous liquid pipeline, the pressure history should consist of a record of pressures measured at regular intervals of not more than 15 seconds such that the pressure-cycle history can be examined to assess the exposure to pressure-cycle-induced fatigue (PCIF). The interval for pressure sampling for a natural gas transmission pipeline could be up to one hour (not an hourly average, high and low values must be captured) because the rate of change with time is usually much slower than is the case for a hazardous liquid pipeline. While a natural gas pipeline tends to have a much lower risk of defect growth from fatigue than a hazardous liquid pipeline, the pressure-cycle history of a natural gas pipeline still needs to be assessed[13].

Another essential part of the operating history of a pipeline is its safety performance in terms of in-service leaks and ruptures that may have occurred over its service life. Examining the history of leaks and ruptures versus time, especially where the causes are known, allows one to assess the risks to the pipeline of failures from the various time-dependent threats, and it also allows one to assess whether or not the risk of continuing failures of any one particular type can become or is becoming excessive. While the term excessive is subjective, it refers to a situation in which replacement becomes the preferred option to continuing repair and mitigative responses.

For steel pipelines, the history of cathodic protection is useful when a repair/replace decision is being considered. 49 CFR 195 requires operators of hazardous liquid pipelines and 49 CFR 192 requires operators of natural gas pipelines to maintain records of cathodically protected pipelines, rectifiers, galvanic anodes and interference bonds and to conduct annual surveys of pipe-to-soil potential readings. Occasionally, an operator may conduct a comprehensive pipe-to-soil potential survey (a "close-interval survey") by walking the right-of-way and taking readings at intervals of generally between 3 feet and 6 feet. Operators are required to correct inadequate levels of protection within a reasonable period of time, and the mitigation may consist of increasing the current at existing rectifiers or adding new rectifiers or anodes, or eliminating stray currents to enhance the pipe-to-soil potentials. Reviewing the history of these types of efforts should be part of any repair/replace decision.

[13] This is particularly true for natural gas pipelines that have never been subjected to a pressure test sufficiently high to assure the absence of potentially large defects, for example, a pipeline with an MAOP of 40% of SMYS that has been tested only to a level of 50% of SMYS.

Records of any monitoring for internal corrosion as well as the use of inhibitors, biocides, and cleaning pigs should be considered in any repair/replace decision.

Records of earth movements and floods and the associated effects on a pipeline, if any, should be examined as part of the repair/replace decision process.

In-Line Inspection Records

In-line inspection (ILI) records for any pipeline that has been inspected could bear significantly on a repair/replace decision. ILI records from metal loss or crack-detection tools will tend to indicate the types of degradation phenomena that may be affecting the segment, and they may also help to pinpoint the most susceptible locations. Results of successive inspections may indicate the rate of deterioration. All such records should be reviewed pursuant to making a repair/replace decision.

Probability of Exceedance analysis of corrosion anomalies can be useful here. If the pipe segment is badly deteriorated (for example it is uncoated or the coating exhibits widespread failure), such an analysis may show that the probability of a leak or rupture in the remaining uninvestigated anomalies cannot be significantly reduced no matter how many additional digs are performed. Such a line would be a candidate for possible replacement.

Direct Assessment Records

For steel pipelines, records of any direct assessments (ECDA, ICDA, or SCCDA) could be useful for making a repair/replace decision. Such data will tend to indicate the types of degradation phenomena that may be affecting the segment, and they may also help to pinpoint the most susceptible locations. Results of successive inspections may indicate the rate of deterioration. All such records should be reviewed pursuant to making a repair/replace decision.

Bell-Hole Examination Records

For a variety of reasons, from time to time, pipeline operators excavate and examine portions of their pipelines. Whenever such excavations are made, Federal Regulations require that operators make inspections of the pipe for external corrosion (see, for example 49 CFR 195.569 for hazardous liquid pipelines and 49 CFR 192.459 for natural gas pipelines). Data obtained from these "bell-hole" examinations can be helpful in making repair/replace decisions. Typical data that one may obtain from a bell-hole examination are pipe condition, diameter

measurements, wall thickness measurements, seam type, coating condition[14], soil resistivity, and pipe-to-soil potentials. These data should be considered.

Repair Records

Pipeline operators are required to keep records of times and locations where repairs are made to their pipelines. The repair records typically indicate where, when, why, and how the pipeline was repaired. These data should be considered in making a repair/replace decision. Analysis of repair rate trends over time or by segment or geographic region may be useful.

Leak Survey Records

Operators of hazardous liquid pipelines are required to inspect their rights-of-way at least 26 times per year (at intervals not exceeding 3 weeks) by flying, walking, driving, or other appropriate means of traversing the right-of-way. While this is done primarily to spot encroachments by digging equipment, it also affords an opportunity to spot leaks. Leakage surveys for natural gas transmission pipelines must be conducted at least once each calendar year (no interval to exceed 15 months.). If the gas is not odorized, the leakage surveys using leak detector equipment must be done twice a year (no interval to exceed 7-1/2 months) in Class 3 locations and four times a year (no interval to exceed 4-1/2 month) in Class 4 locations. Leakage surveys with leak detector equipment are required at least once each calendar year (intervals not to exceed 15 months) for gas distribution systems in business districts and at least once every 5 calendar years (at intervals not exceeding 63 months) for distribution systems outside of business districts. Leak surveys are conducted at a minimum of once every 3 years (no interval to exceed 39 months) for CI and unprotected bare steel distribution lines. These data may be helpful in making a repair/replace decision.

Conditions that Matter in Repair/Replace Decisions

To make sound repair/replace decisions a pipeline operator should consider conditions and circumstances that are likely to have an impact on the ability or inability to repair a pipeline or mitigate integrity threats. These are as follows.

Piggability

For pipelines that are operated at hoop stress levels at or above 30% of SMYS, in-line inspection is a key method for dealing with time-dependent threats to pipeline integrity such as external corrosion, internal corrosion, SCC, and the growth of defects via pressure-cycle-induced fatigue (PCIF). Therefore, the following questions are relevant to making a repair/replace decision.

[14] Areas of disbonded pipe coatings should be inspected for SCC.

- Can the segment accommodate all types of smart pigs?
- Can the segment accommodate some types of smart pigs?
- If only some types of smart pigs can be accommodated, are those smart pigs capable of locating and sizing the anomalies associated with each relevant time-dependent threat?
- If the segment is not currently piggable, can it be made piggable?
- If it cannot be made piggable, can the threats of external corrosion, internal corrosion, and SCC be assessed via ECDA, ICDA, and/or SSCDA?
- Can other types of internal inspection (other than on-stream ILI tools) be used to assess pipeline integrity from the standpoint of all relevant threats?

Pressure Testability

For pipelines that are operated at hoop stress levels at or above 30% of SMYS, pressure testing is another key method for dealing with time-dependent threats to pipeline integrity such as external corrosion, internal corrosion, SCC, and the growth of defects via pressure-cycle-induced fatigue (PCIF). The questions that should be considered in making a repair/replace decision are:

- Can the segment be taken out of service, filled with water, and subjected to a hydrostatic test?
- If the segment cannot be tested with water, would a pneumatic pressure test with inert gas or air to levels permitted by 49 CFR 192 or 49 CFR 195 be sufficient to demonstrate pipeline integrity?
- As a last resort, can the segment be tested safely with natural gas or a liquid petroleum product? (Part 192 limits pressure testing with natural gas to a stress level not exceeding 80% of SMYS in Class 1 locations and to a stress level not exceeding 30% of SMYS in all other class locations. Part 195 limits pressure testing with a petroleum product to fluids that do not vaporize rapidly, and testing with such a medium may not be done in populated areas.)

Operating Stress Level (applies to steel pipe only)

The maximum operating stress level of a pipeline should be considered in making a repair/replace decision because phenomena such as SCC and PCIF generally are not observed to occur in pipelines that operate at low stress levels and because at low stress levels, longitudinal rupture is an unlikely mode of failure. One benchmark level is recognized by both 49 CFR 192 and 49 CFR 195, namely 20% of SMYS. Under 49 CFR 192, gas pipelines that are operated at or above a stress level of 20% of SMYS must be classified as transmission pipelines. Under 49 CFR 195, hazardous liquid pipelines that operate at or below a stress level of 20% of SMYS are considered "low-stress" pipelines. Neither SCC failures nor PCIF failures nor

propagating ductile ruptures are known to have occurred at stress levels below 20% of SMYS. However, propagating brittle fractures have been observed at stress levels below 20% of SMYS.

Another benchmark is 30% of SMYS. Under 49 CFR 192, miter bends of less than 12.5 degrees and wrinkle bends are permitted in natural gas pipelines that are operated at hoop stress levels less than 30% of SMYS. In addition, the pressure testing requirements for natural gas pipelines that operate at stress levels of 30% of SMYS or more differ from those for pipelines that operate at less than 30% of SMYS.

Aside from these regulatory benchmarks, an operator, when considering a repair/replace decision, should carry out an analysis of the possible effects of the maximum operating stress on the likelihood of leaks and ruptures occurring taking into account the actual geometric dimensions of the pipe; its material properties including strength, toughness, and ductile-to-brittle fracture transition temperature; and the composition of the transported product with respect to its ability to drive a propagating fracture.

Legacy Pipe

Legacy pipe means steel pipe manufactured using any now-obsolete technique including furnace butt-welded, furnace lap-welded, low-frequency-welded electric resistance welded (LF-ERW), direct-current-welded electric resistance welded (DC-ERW), single submerged-arc welded (SSAW), or Flash Welded (A.O. Smith) pipe or any pipe with an unknown type of longitudinal seam. Legacy pipe also includes wrought iron pipe, pipe made from Bessemer steel, pipe of unknown specification or pipe for which the yield strength is unknown, and any pipe made prior to 1942 when the minimum levels of API-required manufacturers' pressure tests were raised significantly. Lastly, legacy pipe includes polyethylene (PE) plastic pipe materials that have a history of premature failures from slow crack growth.

Legacy Construction Techniques and Legacy Repair Methods

Legacy construction techniques refer to obsolete and potentially problematic construction techniques such as wrinkle bends in pipelines operated at stress levels at or above 30% of SMYS, miter bends having included angles greater than 3 degrees in pipelines operated at stress levels at or above 30% of SMYS, Dresser Couplings, threaded collars, non-standard fittings, oxyacetylene welds in cross-country transmission pipelines, and bell and spigot joints. Repair methods such as welded patches, half-soles and puddle welds constitute legacy repair methods that are, for the most part, no longer used.

MITIGATIVE RESPONSES TO AVOID OR DELAY REPLACEMENT

In this segment of the report, the mitigative responses appropriate to repair/replace decisions for hazardous liquid transmission pipelines, natural gas transmission pipelines, and natural gas distribution systems are discussed. The mitigative responses of pressure testing, in-line-inspection, and direct assessment as applied to hazardous liquid pipelines and natural gas transmission pipelines are discussed first. These discussions are followed by a discussion of the mitigative responses appropriate to repair/replace decisions in natural gas distribution systems. It is assumed that if it is feasible for an operator to satisfactorily mitigate pipeline integrity threats whenever and wherever such mitigation is required to preserve pipeline integrity, replacing a pipeline can be delayed or avoided altogether.

Pressure Testing

One way to verify the safety and integrity of a pipeline segment is to pressure test it to a level sufficiently above the maximum operating pressure to show that the segment contains no defects that could fail at the operating pressure. Pressure testing can be carried out on any pipeline segment that can be taken out of service for the time required to conduct the test. The pressure test demonstrates the current serviceability of the segment, and the higher the ratio of test pressure to operating pressure is, the more confidence the operator can have that the segment is fit for service and free of injurious defects. Also, the higher the ratio of test pressure to operating pressure is, the longer the time interval will be before retesting is needed. The technical issues that illustrate the effectiveness of pressure testing are presented below. A good summary of the practical aspects of hydrostatic pressure testing is available in a document recently published by the INGAA Foundation[vii].

Why Pressure Tests Work

It is intuitive that a structure can survive a given level of load without failing if that same structure has previously survived a higher level of the same kind of load. The field of "fracture mechanics" provides a more scientific explanation of why pressure testing works. Several different fracture mechanics models exist for predicting failure stress levels of axially oriented, part-through-wall defects in pressurized pipe. These include, but are not necessarily limited to PAFFC[viii], CorLas™[ix], API 579 – Level II[x], API 579 – Level III, the Modified Ln-Sec Model[xi,xii] and the Newman/Raju model[xiii]. Defects in most line pipe materials at normal ambient temperatures tend to fail in a ductile manner, and in such cases the Modified Ln-Sec Model which evolved from an empirical surface flaw equation developed by Maxey[xiv,xv] gives reasonable estimates of the failure stress levels of longitudinally oriented defects. An important exception involves defects in the bond line of a LF-ERW, DC-ERW, or flash-welded pipe material. For defects in the bond lines of such materials, a model that can account for the brittle fracture and/or elastic-

plastic failure behavior as well as plastic collapse behavior may be needed. Models such as PAFFC, Corlas™ or API 579-Level II (or Level III) could be employed. The API 579-Level II approach often uses the Newman/Raju model for assessing the brittle fracture behavior and any appropriate plastic collapse model to assess the plastic collapse behavior. Together they can produce solutions for failure pressures involving brittle fracture, intermediate elastic-plastic fracture, or plastic collapse behavior. As such, API 579-Level II or Level III approaches may be used to assess failure pressure levels not only for defects in the body of the pipe but for defects in LF-ERW, DC-ERW, or flash-welded seams as well, provided that the fracture toughness levels local to the regions of the defects are known. The following examples show how a pressure test to a hoop stress level above the maximum operating stress level removes the threat of failure of a defect at the maximum operating pressure. The first example involves defects in a typically ductile pipe body material, and second involves defects in brittle bond line material.

The failure pressure levels for axial, part-through defects in the body of a 30-inch-OD, 0.375-inch-wall, X52 line pipe material that exhibits a full-size-equivalent Charpy V-notch upper shelf energy (CVN) of 40 ft-lb as predicted by the Elliptical C-equivalent Modified Ln-Sec Model are illustrated in Figure 1.

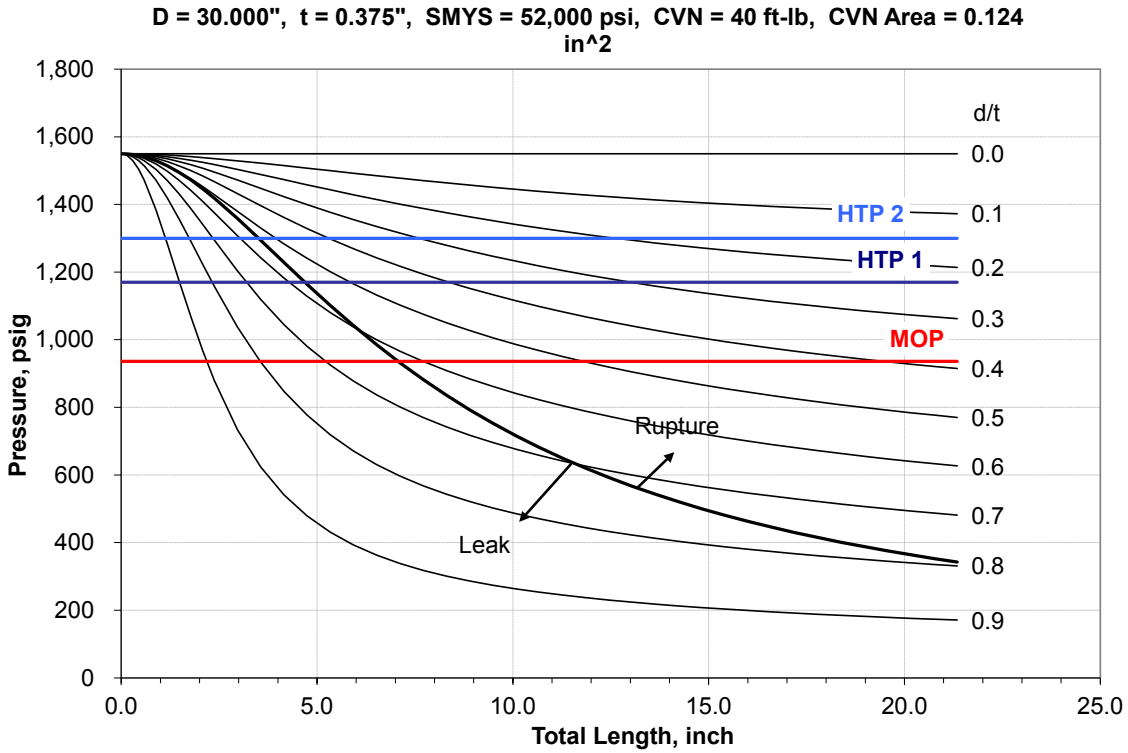


Figure 1. Failure Pressure Levels of Defects in the Pipe Body of a 30-inch-OD, 0.375-inch-wall, X52 Pipe Material that Exhibits a Full-Size-Equivalent Charpy Upper Shelf Energy of 40 ft-lb (Modified Ln-Sec Model)

In the model represented by Figure 1, as with any fracture mechanics model, failure stress (failure pressure in this case) of a defect of a given size is a function of the geometry of the structure (diameter and wall thickness in this case), the size of the defect (length and depth in this case) and the inherent fracture toughness of the material (represented in this case by Charpy impact energy). For this particular model, the failure stress is also a function of the strength of the material (a function of yield strength in this case) because the model is based on the assumption that the mode of failure will be ductile fracture initiation.

A leak/rupture dividing line appears in Figure 1, and it is based on an experimentally-validated theoretic model of the behavior of through-wall defects developed by Folias[xvi] and later modified by Maxey [xvii]. The sizes of defects that leak upon failing lie below and to the left of the leak-rupture curve, whereas those that rupture upon failing lie above and to the right of the leak-rupture curve.

For predicting failure stress levels of defects located in a brittle material such as a LF-ERW or flash-welded seam where one can expect the Charpy energy to be less than 15 ft lb, it is inappropriate to use the Modified Ln-Sec model. Instead, one could use a model such as PAFFC, Corlas™, API 579-Level II, or API 579-Level III. An example prepared by using the API 579-Level II approach is presented in Figure 2. In this application the Newman/Raju model is used to account for the linear elastic (i.e., brittle) fracture behavior, and Maxey's surface flaw equation (described in Reference XII) is used to account for the plastic collapse behavior. The curves in Figure 2 are the result of numerous calculations using the API 579-Level II approach. The intent of Figure 2 is to illustrate the fact that small defects can have a significant impact on the failure pressure of a brittle pipe seam. This is demonstrated via Figure 2 below, where the material is assumed to have a fracture toughness of 25.8 ksi-root-inch (equivalent to 5 ft lb of Charpy energy (CVN) according to the Barsom and Rolfe correlation: $9.35*CVN^{0.63}$).

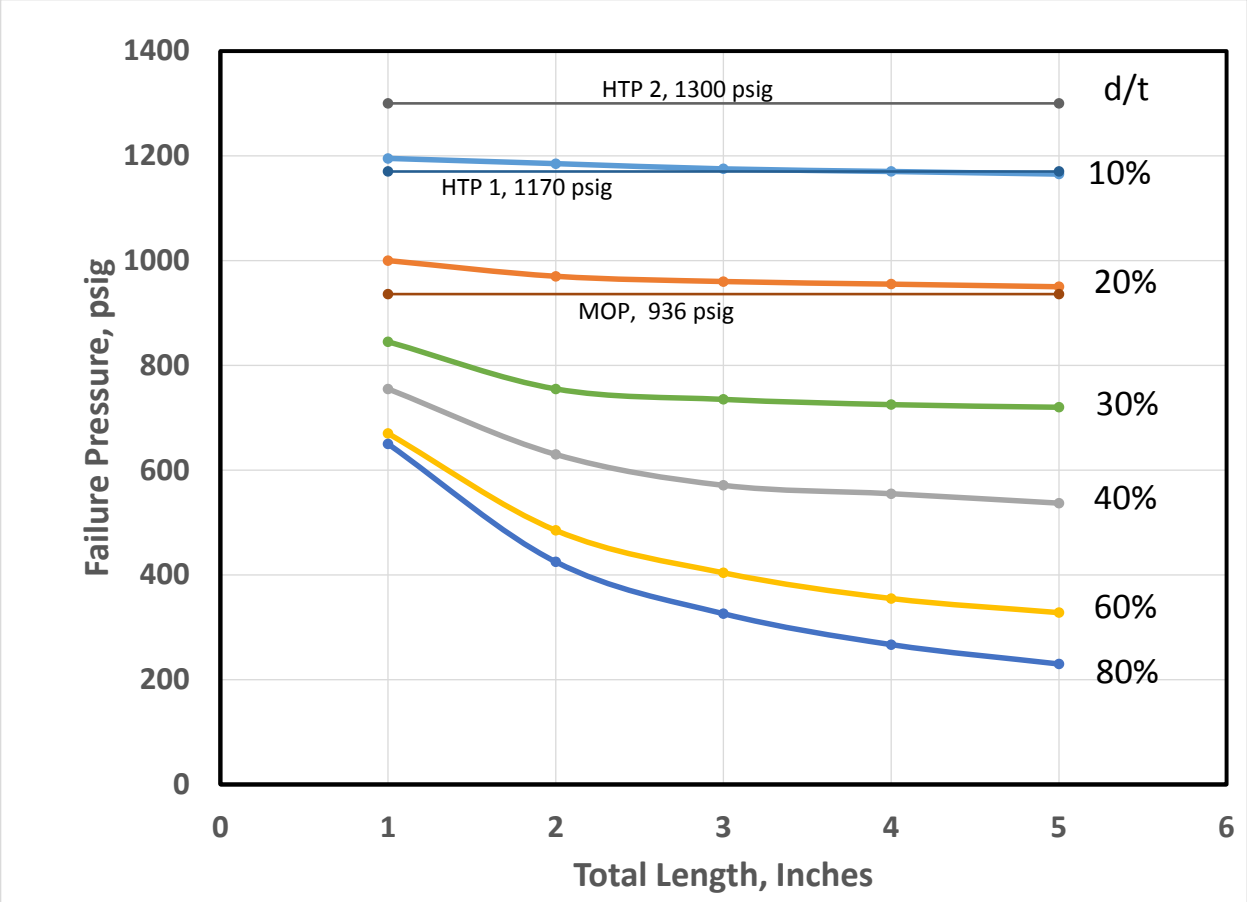


Figure 2. Failure Pressure Levels of Defects in a 30-inch-OD, 0.375-inch-wall, X52 Pipe Seam Material that Exhibits a Fracture Toughness of 25.8 ksi-root-inch (equivalent to 5 ft lb of Charpy energy according to the Barsom and Rolfe correlation) (API 579, Level II)

As in Figure 1, Figure 2 gives predicted failure pressures for various combinations of defect length and depth (actually, depth-to-wall-thickness ratios). The difference is that the failure pressures given in Figure 2 reflect brittle or quasi-brittle behavior whereas those of Figure 1 represent ductile behavior[15].

Given a defect with a particular length and depth, one may determine its failure pressure using Figure 1 if the material is expected to behave in a ductile manner (or from Figure 2 if brittle behavior is expected). For example, the failure pressure of a defect that is 15 inches long and 80% of the way through the wall at its deepest point is 400 psig based on the point in Figure 1 where the curve of d/t = 0.8 intersects the vertical line at 15 inches total length. It is probably

[15] Note that unlike the relatively evenly spaced d/t curves of Figure 1, the d/t curves of Figure 2 become more closely spaced as d/t increases. This is the result of the material behavior trending from quasi-brittle (or elastic-plastic) to brittle over the range of increasing defect depths for the particular range of defect lengths.

not a good idea to try and extrapolate the d/t = 0.8 curve of Figure 2 to a defect length of 15 inches, but Figure 2 predicts that a 5-inch-long defect with d/t = 0.8 would fail at a pressure level of just over 200 psig, much less than the 400 psig predicted for the ductile material where the defect is actually 10 inches longer. Similarly, the failure pressure of a defect that is 5 inches long and 30% of the way through the wall is 1,400 psig based on Figure 1 whereas its failure pressure based on Figure 2 is just over 700 psig. The point is that defects large enough to just barely survive a given pressure level in a ductile pipe body material or ductile pipe seam material would be likely to fail at significantly lower pressures if the same-size defects resided in a brittle LF-ERW or flash-welded seam.

To resume demonstrating how pressure testing works, consider two situations, one in which the material fails in a ductile manner and one in which the material fails in a brittle manner. The maximum operating pressure (MOP) is 936 psig (72% of SMYS) as represented by the horizontal line labeled MOP in both Figure 1 and Figure 2. A pressure test to 1,170 psig (90% of SMYS) is represented by the HTP 1 lines, and a pressure test to 1,300 psig (100% of SMYS) is represented by the HTP 2 lines in both figures. The following table, Table 9, gives the depth-to-thickness ratios taken from Figure 1 and Figure 2 that would cause failures at the three pressure levels (936 psig, 1,170 psig, and 1,300 psig) for defects with lengths of 1, 2, 5, 10, 15, and 20 inches for the 40-ft-lb ductile material and for lengths of 1, 2, and 5 inches for the 5-ft-lb brittle material.

Table 9. Differences in Defect Sizes that Cause Failures at Various Pressures for a 30-inch-OD, 0.375-inch-wall, X52 Material Depending on Whether the Material Fails in a Ductile Manner or a Brittle Manner

Defect Length, inches	d/t, %					
	Ductile Behavior Using Figure 1 (CVN = 40 ft lb)			Brittle Behavior Using Figure 2 (CVN = 5 ft lb)		
	MOP 936 psig	HTP 1 1,170 psig	HTP 2 1,300 psig	MOP 936 psig	HTP 1 1,170 psig	HTP 2 1,300 psig
1	97	95	92	23	11	5
2	92	85	76	22	10	4
5	71	55	42	21	10	4
10	54	36	24	-	-	-
15	45	27	18	-	-	-
20	40	23	15	-	-	-

First, consider the 40-ft-lb ductile material. Note that each depth-to-thickness ratio at a particular defect length represents a lower bound value of depth-to-thickness ratio at a particular pressure level. All defects with the same length but greater depth-to-thickness ratios would fail at lower pressure levels. Hence, the test represented by HTP 1 (1,170 psig) causes

failure of all 10-inch-long defects with depth-to-thickness ratios exceeding 36%, and the test represented by HTP 2 (1,300 psig) causes failure of all 10-inch-long defects with depth-to-thickness ratios exceeding 24%. This means that after the HTP 1 test, any 10-inch-long, 54%-through or deeper defect that would cause failure at or below the MOP would have been eliminated by the test. The HTP 2 test eliminates all 10-inch-long defects deeper than 24% through the wall, so it is more effective than the HTP 1 test for assuring safe operation at the MOP. Note that similar relationships exist for each of the lengths in Table 9.

Next consider the 5-ft-lb brittle material. As in the case of the 40-ft-lb material, each depth-to-thickness ratio at a particular defect length represents a lower bound value of depth-to-thickness ratio at a particular pressure level. All defects with the same length but greater depth-to-thickness ratios would fail at lower pressure levels. Hence, the test represented by HTP 1 (1,170 psig) causes failure of all 5-inch-long defects with depth-to-thickness ratios exceeding 10%, and the test represented by HTP 2 (1,300 psig) causes failure of all 5-inch-long defects with depth-to-thickness ratios exceeding 4%. This means that after the HTP 1 test, any 5-inch-long, 21%- through or deeper defect that would cause failure at or below the MOP would have been eliminated by the test. The HTP 2 test eliminates all 5-inch-long defects deeper than 4% through the wall, so it is more effective than the HTP 1 test for assuring safe operation at the MOP.

On the basis of Figures 1 and 2 and Table 9, one can see why pressure testing works. It eliminates or proves the absence of defects that would fail at pressure levels lower than the test pressure. It should also be clear from Figures 1 and 2 and Table 9 that the higher the ratio of test pressure to the maximum operating pressure is, the less likely it is that a failure will occur at the maximum operating pressure. Note that the same is true whether the material exhibits ductile (i.e., a typical pipe body material) or brittle behavior (i.e., typical of the bond line region of a LF-ERW seam or a flash-welded seam) it's just that the defect sizes causing failure at a given stress level would be much smaller for the brittle material. But, a higher-test-pressure-to-operating-pressure ratio (1,300 psig to 936 psig) is still more effective at assuring pipeline integrity than a lower test-pressure-to-operating-pressure ratio (1,170 psig to 936 psig) even for a brittle material.

The concepts embodied in Figure 1 and Figure 2 demonstrate that if defects can grow after the test, the margin of safety will be eroded with the passage of time, and retesting will be required to once again to revalidate the integrity of the pipeline. Note that the time to failure after the test will be longer for a higher test-pressure-to-operating-pressure than for a lower test-pressure-to-operating-pressure. That is because defects have to grow to a certain predictable size in order for a failure to occur at the maximum operating pressure, and the starting sizes of defects that survive a test decrease with increasing test pressure.

Limitations

Some important limitations on pressure testing need to be considered when a test is contemplated for integrity assessment of an in-service pipeline. First, the pipeline must be taken out of service or at least closed to transporting the product. The time out of service represents lost revenue and possible interruption of service to customers and shippers. In the case of a single transmission pipeline supplying a gas distribution system or in the case of a gas main, the disruption of customers usually cannot be tolerated, and hence, pressure testing is seldom if ever conducted on existing pipe segments in such systems. Pressure testing in such systems is usually only applied to new or replaced pipe segments prior to their being placed in service. Even where testing is feasible, the time out of service can still have an impact on revenue and shippers. Moreover, the time out of service is often hard to predict because of the possibility of leaks and ruptures occurring during the test. In test scenarios where the product must be displaced by water before the test and the water must then be displaced by the product after the test, the time out of service can range of days to weeks. Longer times out of service are common if leaks or ruptures occur. Each leak or rupture that occurs can be expected to add at least one day to the time of testing, and the locating of a very small leak may require several days of effort. To find small leaks during the test it may be necessary to add a specialized leak detection gas to the water or test medium to help find very small leaks.

For the vast majority of cases where pressure testing is chosen for integrity assessment of high-pressure hazardous liquid pipelines or high-pressure gas transmission pipelines, the test medium will be water. Not just any water can necessarily be used. To avoid introducing bacteria or corrosive compounds into the pipeline, potable water purchased from a utility is often the preferred test medium. If untreated water must be used, it is prudent to run a biocide disinfectant slug after the test and prior to the line being placed into service. The water becomes contaminated by residual liquids and solids remaining after the product is displaced, and the pipeline operator usually must pay for satisfactory treatment of the water before discharging it to a sewer system, a river, or a reservoir.

It has been demonstrated by actual operating experience[xviii] that testing natural gas pipelines that are operated at 72% of SMYS to pressure levels at or above 90% of SMYS (a 1.25 test-pressure-to-operating-pressure ratio) eliminates manufacturing defects that otherwise might cause in-service failures. However, there are circumstances that one should be aware of wherein service failures have occurred after a pressure test to at least 1.25 times MOP. A recent review of the track record of pressure testing[xix] revealed the existence of such cases. The authors of Reference XVIII (Page 18) documented a case where a pressure surge that caused pressures to rise significantly above the MOP resulted in an in-service failure. It was speculated that additional in-service failures may have also involved unknown or unmeasured pressure upsets where the MOP was significantly exceeded. In other cases, it was evident that

retests might have prevented the in-service failures if conducted in a timely manner to eliminate defects that were growing by fatigue or another time-dependent phenomenon. The authors noted that pressure testing is not effective at preventing subsequent leaks from short, deep defects that survive a given pressure test. In any case this study showed that when pressure tests were conducted at timely intervals with pressure levels exceeding 90% of SMYS and when pressure excursions significantly in excess of MOP were prevented, no subsequent in-service ruptures occurred in the subject pipelines.

As noted in the previous paragraph, not all leaks can be prevented by high-pressure testing. Leaks might occur a short time after a pressure test from short, deep defects. This phenomenon is explainable in terms of the previous fracture mechanics discussion on the way testing works. For example, Table 9 shows that a 1-inch-long, 92% through-the-wall defect could survive a test to 1,300 psig (HTP1). Yet, this defect needs to grow only to a depth of 97% through the wall to fail at the MOP. A 2-inch-long, 76% through-the-wall defect also could survive a 1,300-psig test, and it would have to grow to a depth of 92% of the wall thickness to fail at the MOP. In contrast, the longer defects (5, 10, 15, and 20 inches) have to grow to depths of 71, 54, 45, and 40% through the wall to fail at the MOP. This indicates that short, deep defects can survive a high-pressure test but grow to failure a short time after the test. As indicated by the leak/rupture curve, such defects would tend to fail as leaks because they are too short to fail as ruptures. However, the fact that a pressure test may not be very effective at preventing future leaks could be a limitation on the effectiveness of such testing, particularly for a hazardous liquid pipeline where a small leak occurring over a period of time can create significant environmental damage. In the case of short, deep corrosion pits such leaks can usually be prevented by using ILI to find them either before the test is performed or shortly thereafter, so that they can be repaired. However, ILI has not been particularly successful at locating short, deep lack-of-fusion defects in ERW seams.

A phenomenon sometimes associated with pressure testing that constitutes more of nuisance than a real limitation is the likelihood of occurrence of "pressure reversals". Pressure reversals are nothing new; they have been observed in pressure testing for a long time[xx]. A pressure reversal is said to have occurred when a test failure takes place at a pressure level lower than the level achieved in a recent pressurization. The potential for such an occurrence tends to be unsettling because it suggests that reaching a given level of test pressure may not be an absolute guarantee that the margin of safety is equal to the test-pressure-to-operating-pressure ratio associated with that pressure level. However, research has shown how pressure reversals arise and that they are normally not a threat to the integrity of a pipeline after it has been subjected to a pressure test.

Research[xxi] has demonstrated that when pressurized to a near-failure level, a defect will tend to grow, and as its failure level is approached, the growth will continue until failure occurs even if

the pressurization is stopped and the pressure is held constant. If the pressure is suddenly released when a defect is at this "creep" stage, the defect likely will be incapable of enduring another pressurization to the same level. Because of the accumulated damage on one or more prior pressurizations and depressurizations such a defect is likely to fail on a subsequent pressurization at a level below that of the recent prior pressurization. This difference in failure pressure from that of the prior pressurization is termed a "pressure reversal". In effect, a pressure reversal is an extreme case of low-cycle fatigue. Typically, pressure reversals are encountered during a test in which multiple defects fail, each failure causing a sudden depressurization to zero, requiring re-pressurization to continue the test.

Fortunately, experience has shown[xxii] that the likelihood of a pressure reversal occurring decreases exponentially with the difference in pressure between its failure pressure and the highest previous pressure. Thus, for example, while a pressure reversal equal to 1% of the test pressure might be expected to occur in one of every 10 to every 100 pressurizations, a pressure reversal exceeding 20% of the test pressure would be expected to occur only once in several million pressurizations. As a result one need not be concerned that a defect surviving a pressure test might subsequently fail upon pressurization to the maximum operating pressure. The chance of such an occurrence is not zero, but it is so small that it constitutes a negligible risk. Moreover, if a test is carried out successfully with no test failures and depressurized slowly, then there would seem to be little likelihood of a pressure reversal of any size occurring.

A significant limitation on pressure testing is the fact that a test does not identify the types or locations of defects that may exist after the test. As Figure 1 shows, no matter what test pressure level is chosen (short of the level that would cause sound pipe to burst), the possibility of defects with failure pressures above the test pressure remaining in the pipeline certainly exists. The pipeline operator will have no knowledge of the natures or locations of any such defects. The only way to assure that such defects will not grow to failure at the operating pressure at some time in the future after the test is to find and eliminate them (for example, by means of ILI) or to subject the pipeline to another pressure test before they have time to grow to failure in service. The concept of timely retesting is explained in the next section.

Finally, it is noted that hydrostatic testing is not effective for preventing failures from HSC in pipe body hard spots or hard heat-affected zones of ERW seams. This is because hydrostatic testing will not cause a pipe body hard spot or a hard heat-affected zone of an ERW seam to fail unless it is already cracked sufficiently by HSC. It is not possible to predict the rate of growth for HSC. If HSC starts to occur, the failure can occur rapidly, even instantaneously, so there is no way to predict when a hydrostatic test would be effective. The practical means for mitigating an HSC threat (which do not include hydrostatic testing) are discussed separately later in these guidelines.

Trade-off between Test Pressure and Retest Interval

As indicated previously, pressure testing does not eliminate or prove the absence of all defects, only those that are large enough to fail at the test pressure. Defects that survive the test may grow with time after the pipeline is restored to service. Defects that have the potential to grow with time in service include manufacturing defects that grow from pressure-cycle-induced fatigue (PCIF), corrosion-caused metal loss, and SCC. Conducting periodic pressure tests is an acceptable method to assure that none of these can cause an in-service failure, though it may not always be the best method (e.g., preventing in-service failures from corrosion-caused metal loss via ILI is usually a more efficient method than pressure testing).

If a pipeline operator chooses to use periodic pressure testing to prevent failures from time-dependent defect growth, each test must be done in a timely manner to prevent in-service failures. Higher test-pressure-to-operating-pressure ratios lead to longer intervals between tests because as test pressure is increased, the maximum size of surviving defects decreases. The number of test failures tends to grow exponentially with increasing test pressure, and the number of test failures that can be tolerated generally sets an upper bound on test pressure. Also, if pipe is tested to pressure levels approaching or exceeding 110% of SMYS, some yielding of pipe may occur. Most pipeline operators prefer to either limit the amount of yielding or to avoid it altogether. Described below are methods a pipeline operator can use to estimate an appropriate combination of test pressure and retest interval.

Predicting Retest Intervals for Defects Having a Constant Rate of Growth

It is usually assumed that corrosion-caused metal loss and SCC grow at constant rates with the passage of time. For any such growth mechanism it is possible to predict an appropriate retest interval using a defect failure stress prediction model such as the Modified Ln-Secant Model described in Figure 1 or the API 579-Level II model described in Figure 2. Because the principle is the same whether the material is ductile or brittle, the process for predicting retest intervals described below is based on the assumption that the material exhibits ductile fracture initiation. Hence, the curves of Figure 1 based on the Modified LnSec model will be used. The same principle could be applied to a material that exhibits brittle fracture behavior. Note, however, that because the defects that cause failures at the various test pressure levels and at the MOP are much smaller for the brittle material, the predicted retest intervals are likely to be much shorter for the defects in a brittle material for the same defect growth rates.

The data in Table 9 for the ductile (40-ft-lb) material indicates that a pressure test to 1,170 psig (HTP 1) would be expected to eliminate 1-inch-long defects that are deeper than 95% of the wall thickness. The data also indicates that if a 1-inch-long defect that is 95-percent-through survives the test, it must grow (in depth only) to a depth of 97% through-the-wall to fail at the MOP of 936 psig. Since the wall thickness of the pipe was given as 0.375 inch, this 2%-of-wall-

thickness growth is equal to 0.0075 inch. If the growth rate is 0.001 inch per year, the time to failure is 7.5 years. It is common to impose a safety of factor of 2 on this calculated time to failure to get an appropriate retest interval. The retest interval, then, is 3.75 years for a pressure test to 1,170 psig. The retest intervals for all six of the defects listed in Table 9 are shown in Table 10 for the 1,170-psig test (HTP 1) based on the type of calculation just described for the 1-inch-long defect.

Table 10. Retest Intervals for a Pressure Test to 1,170 psig with a Test-Pressure-to-Operating-Pressure Ratio of 1.25

Length, inch	d/t, MOP, %	d/t, HTP 1, %	Δ%	Δ wall Thickness,	Time to Failure At rate 0.001 inch	Retest Interval,
1	97	95	2	0.0075	8	4
2	92	85	7	0.02625	26	13
5	71	55	16	0.06	60	30
10	54	36	18	0.0675	68	34
15	45	27	18	0.0675	68	34
20	40	23	17	0.06375	64	32

The effect of increasing the test-pressure-to-operating-pressure ratio can be seen by comparing the results in Table 10 with those in Table 11. Table 11 presents retest intervals for the same 30-inch-OD pipeline with a defect growth rate of 0.001 inch/year but with a test to a pressure level of 1,300 psig (100% of SMYS) rather than to 1,170 psig (90% of SMYS) as was the case presented in Table 10.

Table 11. Retest Intervals for a Pressure Test to 1,300 psig with a Test-Pressure-to-Operating-Pressure Ratio of 1.39

Length, inch	d/t, MOP, %	d/t, HTP 2, %	Δ%	Δ wall Thickness,	Time to Failure At rate 0.001 inch	Retest Interval,
1	97	92	5	0.01875	19	9
2	92	76	16	0.06	60	30
5	71	42	29	0.10875	109	54
10	54	24	30	0.1125	113	56
15	45	18	27	0.10125	101	51
20	40	15	25	0.09375	94	47

The safe retest interval for the long defects is 47 years for the 1,300 psig test (a test-pressure-to-operating-pressure ratio of 1.39) compared to the safe retest interval of 30 years for the long defects after a test to 1,170 psig (a test-pressure-to-operating-pressure ratio of 1.25).

Pipeline operators need to be aware of the fact that the benefit of a given test-pressure-to-operating-pressure ratio decreases as the maximum operating stress level decreases as a percentage of SMYS. Consider the case where the 30-inch-OD, 0.375-inch-wall, X52 pipeline with a Charpy upper shelf energy of 40 ft-lb used in the previous examples is operated at a maximum stress level of 50% of SMYS (650 psig). The same defects in terms of lengths now have to be deeper to fail at the maximum operating pressure of 650 psig than they would have to be to fail at the maximum operating pressure of 936 psig. If a test-pressure-to-operating-pressure of 1.25 times MOP is utilized (referred to as HTP 3), the test pressure would be 813 psig. The results of such a test in terms of retest intervals can be seen in Table 12.

Table 12. Retest Intervals for a Pressure Test to 813 psig with a Test-Pressure-to-Operating-Pressure Ratio of 1.25

Length, inch	d/t, MOP, %	d/t, HTP 3, %	Δ%	Δ wall Thickness, inch	Time to Failure At rate 0.001 inch per year, years	Retest Interval, years
1	99	98	1	0.00375	4	2
2	95	93	2	0.0075	8	4
5	83	77	6	0.0225	23	11
10	72	62	10	0.0375	38	19
15	64	53	11	0.04125	41	21
20	60	48	12	0.045	45	23

The data in Table 12 indicate that the safe retest interval for the longer defects is 19 years (the 5-inch-long defect in this case is predicted to fail as a leak). By comparison the test to 1,170 psig for a maximum operating pressure of 936 psig (with the same test-pressure-to-operating-pressure ratio of 1.25) assures a retest interval of 30 years for the longer defects. This situation is created by the fact that the sizes of defects remaining after a test increase with decreasing test pressure.

If the example pipeline is operated at 650 psig because it is a natural gas transmission pipeline in a Class 3 area, then the operator would have to conduct a pressure test to 975 psig to comply with 49 CFR 192.619(a)(2)(ii) (test-pressure-to-operating-pressure ratio of 1.5). Table 13 indicates that such a test would result in a safe retest interval of 39 years for the longer defects. This retest interval is shorter than the 47-year interval associated with testing a similar pipeline with a maximum operating pressure of 936 psig to a level of 1,300 psig (a test-

pressure-to-operating-pressure ratio of 1.39). These comparisons illustrate that pipelines that are operated at relatively low stress levels need to be tested with higher test-pressure-to-operating-pressure ratios than high-stress pipelines to achieve to same length of retest interval.

Two empirical equations are given for selecting appropriate test-pressure-to-operating-pressure ratios for a pressure test based on the absolute operating stress level are presented in TTO6[xxiii]. "TTO6" was a special report on spike hydrostatic testing that was prepared for the Research and Special Programs Administration[16] of the U.S. Department of Transportation. One of the equations is associated with pressure-cycle-induced-fatigue (PCIF), and the other is associated with SCC. They are as follows.

For PCIF:

$$HTP/MOP = -0.00736(\%SMYS\ at\ MOP) + 1.919 \qquad \textbf{Equation 1}$$

For SCC:

$$HTP/MOP = -0.02136(\%SMYS\ at\ MOP) + 3.068 \qquad \textbf{Equation 2}$$

where

HTP stands for hydrostatic test pressure, psig

MOP stands of maximum operating pressure, psig

One can determine from Equation 1 that the suggested HTP/MOP ratio for a pressure test for a pipeline that is operated at 72% of SMYS is 1.39, and that the suggested HTP/MOP ratio for a pressure test for a pipeline that is operated at 50% of SMYS is 1.55. Similarly, one can determine from Equation 6 that the suggested HTP/MOP ratio for a pressure test for a pipeline that is operated at 72% of SMYS is 1.53, and that the suggested HTP/MOP ratio for a pressure test for a pipeline that is operated at 50% of SMYS is 2. It is emphasized that these are only guidelines. An operator should evaluate the circumstances of each particular pipeline segment to be pressure tested to select the appropriate test-pressure-to-operating-pressure ratio.

[16] The Research and Special Programs Administration (RSPA) was the predecessor Federal agency to PHMSA.

Table 13. Retest Intervals for a Pressure Test to 975 psig with a Test-Pressure-to-Operating-Pressure Ratio of 1.5

Length, inch	d/t, MOP, %	d/t, HTP 4, %	Δ%	Δ wall Thickness,	Time to Failure At rate 0.001 inch	Retest Interval,
1	99	97	2	0.0075	8	4
2	95	91	4	0.015	15	8
5	83	69	14	0.0525	53	26
10	72	51	21	0.07875	79	39
15	64	42	22	0.0825	83	41
20	60	37	23	0.08625	86	43

Predicting Retest Intervals from Prior Test Results for Defects Having a Constant Rate of Growth

Fessler and Rapp[xxiv] developed a novel approach to predicting retest intervals for SCC. Though developed for use with pipelines affected by SCC, it would seem that the method is applicable to any defect growth mechanism where the rate of growth is constant. This method involves conducting an initial pressure test after an SCC problem has been identified, and conducting a second pressure test an appropriate amount of time after the first test. The appropriate amount of time can be estimated via the type of analysis described above. However, all future tests after the second can then be determined on the basis of a rational schedule established as follows.

The pressure level reached in the first pressure test is used to establish the maximum sizes of remaining defects. The time for the second test can be calculated as shown previously using a failure pressure prediction model and a rate of defect growth that has either been established from the history of the pipeline of interest or can be obtained from standards such as ASME B31.8S or research studies[xxv]. Alternatively, one can use observed depths of defects and a distribution of starting times of defect growth via a Monte Carlo simulation to obtain a probable maximum crack growth rate[xxvi].

The second test allows one to calculate the "effective" crack growth rate for establishing the time of the "next" retest. The time of the first hydrostatic test is again used as the starting point and the "next" hydrostatic test allows one to calculate the crack growth rate for establishing the time to conduct the "next after the next" hydrostatic test. Certain assumptions must be made:

- The pipeline contains SCC (or another type of time-dependent defect with a constant rate of growth).

- The growth rate for surviving cracks will be less than the growth rate for a crack that has previously failed.
- Cracks initiating in the future will not fail before an existing crack fails.
- Future operating conditions will be no more severe than past operating conditions.
- The crack depth increases linearly with time.
- There is a direct relationship between failure pressure and defect size (the larger the defect, the lower its failure pressure).
- Successive hydrostatic tests are carried out at the same pressure.

The Fessler/Rapp approach focuses on an "important" crack that is "zero" depth at the time of the first test. The important crack is assumed to be the right depth to barely survive the second test and that it becomes deep enough to fail at the MOP/MAOP some time after the second test. The projected time required for the important defect to grow to failure at the MOP/MAOP becomes the maximum time interval before the third test must be performed. The process for projecting the times for the fourth, fifth, and subsequent tests involves the crack starting at zero-size after the first test and growing to a size that just survives the current test. This crack is assumed to grow after the current test until it becomes large enough to fail at the MOP/MAOP. The time for the next test is less than or equal to the time it takes for the crack to grow to failure at the MOP/MAOP.

Cracks that are larger than zero-size at the time of the first test will either fail in service before the next test (in which case their growth rate does not matter and the arbitrarily chosen interval was too long) or survive the next test (in which case their growth rate is less than that of the important crack). If a crack that is zero-size at the time of the first test grows to a size that fails in service before the second test is conducted, the arbitrarily chosen interval was too long.

A crack that is zero-size at the time of the first test and grows to a size that fails during the second test is not important in establishing the next retest time, but its growth rate is higher than that of the important crack. It is assumed that the faster growing crack is not important because it is eliminated by the test. Cracks of any size that survive both the first test and the second test will have growth rates less than or equal to the important crack growth rate.

If no factor of safety is employed, the important crack will be on the verge of failure at the MOP at the time of the next test.

The equation for the time of the next test is:

$$T_{[(n-1),(n)]} = T_{(\text{cummulative through n-1})}\left(\frac{HTP - MOP}{FSP - HTP}\right) \qquad \textbf{Equation 3}$$

where: HTP is hydrostatic test pressure

MOP/MAOP is maximum (allowable) operating pressure

FSP is the pressure corresponding to flow stress

$T_{n-1,n}$ is the time interval between tests n-1 and n

n represents the current test

n-1 represents the test prior to the current test

$T_{(cumulative\ through\ n-1)}$ represents the time from the first test through the test prior to current test

Each successive interval will be larger than the previous interval. The recommended value of flow stress is the average of the actual measured yield and ultimate strengths of the material. If these values are unknown, an alternative is to use the specified ultimate strength of the material. The use of a relatively high value of flow stress leads to conservative estimates of retest intervals because it allows larger starting defect sizes.

An example of the use of the Fessler/Rapp method is shown in Figure 3. The example involves a 30-inch-OD, 0.375-inch-wall, X52 pipeline. The actual measured yield strength is assumed to be 60,000 psi, and the actual measured ultimate strength is assumed to be 80,000 psi. It is assumed that each hydrostatic test will be carried out at a pressure level of 1,430 psig (110% of SMYS). It is also assumed that the interval between the first and second hydrostatic tests was 2 years. In a real situation any reasonable interval between tests can be chosen, and the shorter the interval, the more conservative will be the analysis. There is a risk of a service failure from SCC occurring after the first test if too long an interval is assumed.

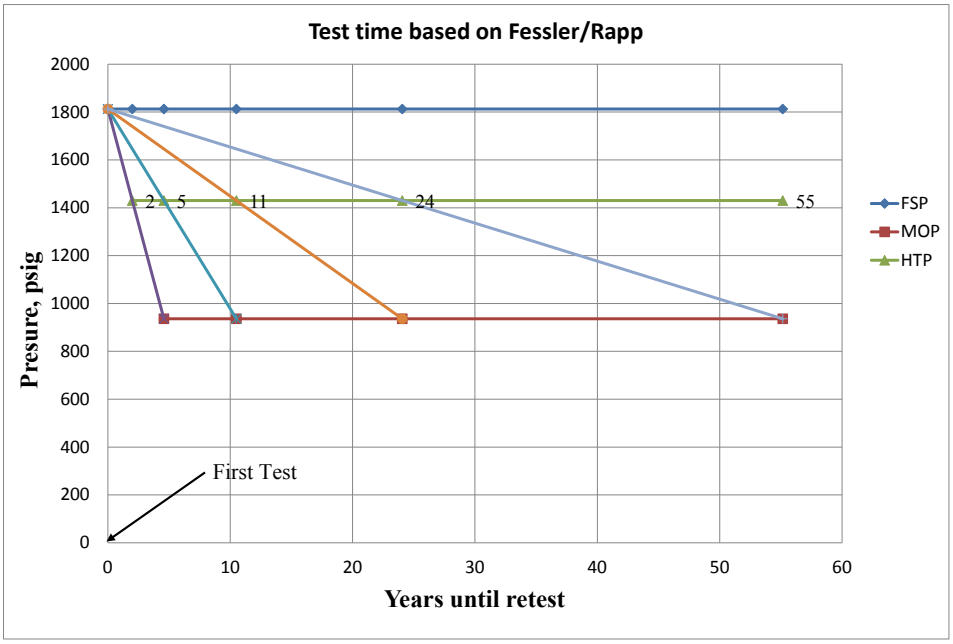


Figure 3. Test Intervals Based on Fessler/Rapp

The calculated times for retesting based on this approach are:

- 2 years after the first test
- 5 years after the first test
- 11 years after the first test
- 24 years after the first test
- 55 years after the first test

The horizontal lines on Figure 3 represent the flow stress[17] pressure of 1812.5 psig, the test pressure of 1430 psig, and the maximum operating pressure of 936 psig. Note that the test times are based on the sloping lines all radiating from the flow stress pressure and Year Zero. The maximum retest interval is determined when the failure pressure of the important crack decreases to the MOP. If a factor of safety is desired, one way to achieve that with this method is to assume that the first interval was 1 year instead of the actual interval of 2 years (half the time). If this were done the calculated times for retesting would be:

- 1 year after the first test
- 2 years after the first test

[17] Flow stress is a material property, It is usually defined as the tensile stress level at which the material will fail. It is above the actual yield strength of the material but usually less than the ultimate tensile strength of the material.

- 5 years after the first test
- 12 years after the first test
- 28 years after the first test

Either way it is seen that the Fessler/Rapp approach will always predict increasing retest intervals.

A modified version of the Fessler/Rapp approach has been proposed by Sen and Kariyawasam[xxvii]. The modified approach (referred to herein as the Modified Fessler/Rapp) involves only one major change. Instead of taking the starting point of zero depth for the important crack as the time of the first test, the modified approach assumes that the starting point of zero depth for the important crack after each test is the year of the previous test. The equation for the modified approach is:

$$T_{[(n-1),(n)]} = T_{[(\boldsymbol{n-2}),(n-1)]}\left(\frac{HTP - MOP}{FSP - HTP}\right) \qquad \textbf{Equation 4}$$

The only term that is different is $T_{[(n-2)(n-1)]}$. This is simply the time interval between the last test and the test before the last test. Based on the same conditions that were used to construct Figure 3 (Fessler/Rapp), the results of a Modified Fessler/Rapp approach are shown in Figure 4.

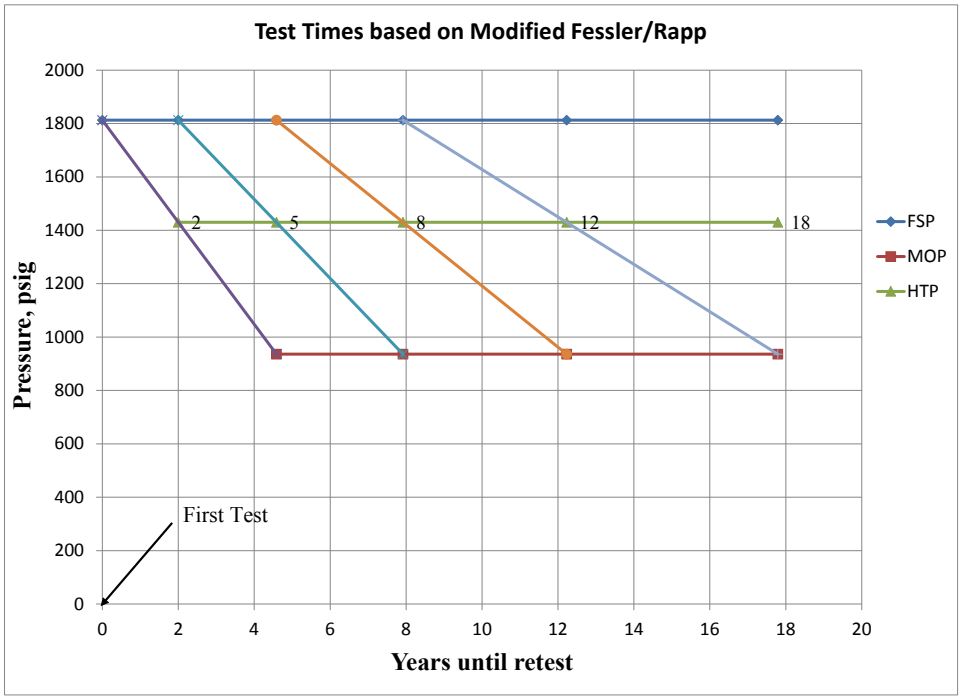


Figure 4. Test Intervals Based on Modified Fessler/Rapp

The calculated times for retesting based on this approach are:

- 2 years after the first test
- 5 years after the first test
- 8 years after the first test
- 12 years after the first test
- 18 years after the first test

As in the Fessler/Rapp approach, the maximum retest interval is determined when the failure pressure of the important crack decreases to the MOP. If a factor of safety is desired, one way to achieve that with this method is to assume that the first interval was 1 year instead of the actual interval of 2 years (half the time) as was possible with the original Fessler/Rapp Method. If this were done the calculated times for retesting would be:

- 1 years after the first test
- 2 years after the first test
- 4 years after the first test
- 6 years after the first test
- 9 years after the first test

Comparing the Modified Fessler/Rapp approach to the original Fessler/Rapp approach, one finds that the former gives more conservative (i.e., shorter) retest intervals. Another feature of the modified approach is that, unlike with the original method, the retest intervals under certain circumstance may actually decrease with time. That is not possible with the original method. For example, using the same parameters as before except changing the test pressure from 1,430 psig (110% of SMYS) to 1,300 psig (100% of SMYS), one gets the results shown in Figure 5.

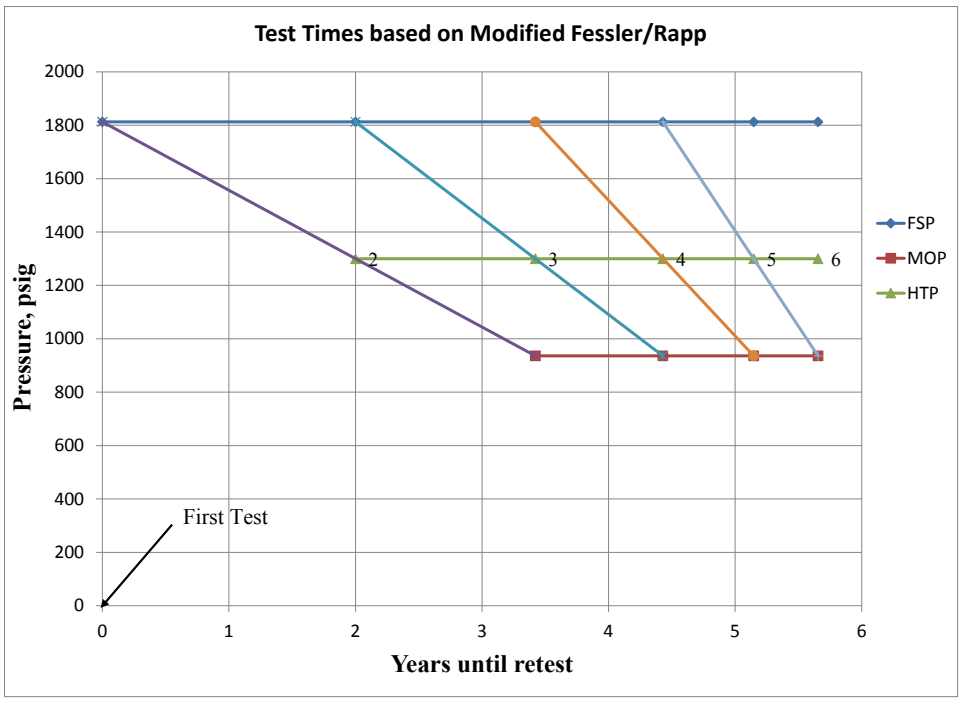


Figure 5. Test Intervals Based on Modified Fessler/Rapp that Decrease with Time

Whether or not this is reasonable, it does point out the importance of test-pressure-to-operating-pressure ratio. Again, it is clear that the higher that ratio is for a given situation, the longer will be the minimum required retest interval. It is noted that making the same change in test pressure using the original Fessler/Rapp approach results in decreases in the retest intervals as well though the intervals still increase with each test. The effect is shown in Table 14.

Table 14. Effect of Test-Pressure-to-Operating-Pressure Ratio Based on the Original Fessler/Rapp Model

Test Number	Years to the Test After the First Test With a Test to 100% of SMYS	Years to the Test After the First Test With a Test to 110% of SMYS
1	2	2
2	3	5
3	6	11
4	10	24
5	17	55

Predicting Retest Intervals for Defects Having a Non-Constant Rate of Growth

One form of defect growth that is characterized by a non-constant rate of crack growth is pressure-cycle-induced fatigue (PCIF). PCIF is a recognized threat to the integrity of a

hazardous liquid pipeline. PCIF failures are not believed to be a near-term threat to natural gas pipelines because of their less-frequent and lower-amplitude pressure cycles. But, whatever the timing, the threat of failure from PCIF can be addressed by periodic integrity assessment. Integrity assessment can be accomplished either by pressure testing or by in-line inspection (ILI) using a suitable crack-detection tool. In this section the use of pressure testing to mitigate a PCIF threat is discussed.

Scheduling retesting to mitigate PCIF involves fatigue-crack-growth analysis. The analysis involves establishing the initial sizes of defects, applying representative operational pressure cycles to cause the defects to grow, and determining the number of pressure cycles required to cause the defects to attain (final) sizes that will cause a failure at the maximum operating pressure (MOP) of the pipeline. The number of pressure cycles required to grow the initial defects to failure corresponds to a certain period of time, so the output of the analysis is a time to failure for each defect considered. A factor of safety is then applied to the time to failure so that a response is made well before any growing defect can reach a size that would cause failure at the MOP.

A commonly-used basis for fatigue crack growth modeling is the "Paris-law" approach named after its principal developer[xxviii]. The Paris-law equation is generally written as follows.

$$\frac{da}{dN} = C(\Delta K)^n \qquad \textbf{Equation 5}$$

where:

da/dN is an increment of crack growth, *inch/cycle*

C and *n* are constants for a particular material and environment

ΔK is the change in stress intensity factor at the tip of the fatigue crack during a cycle of changing applied stress, $psi\sqrt{inch}$

ΔK is calculated using the Raju/Newman[xi] equation which has the form:

$$\Delta K = F\Delta\sigma\sqrt{\pi a} \qquad \textbf{Equation 6}$$

where:

F is a constant that depends on the shape of the stressed element, the ratio of defect depth to wall thickness, the ratio of defect depth to defect length, and the position of the tip of the crack
Δσ is the change in stress during a cycle of loading and unloading, psi
a is the depth of a part-through-wall crack, inch

Note that ΔK is a function of the square root of a. This means that even if the stress cycle, $\Delta\sigma$, is constant, ΔK will increase with the passage of time (as cycles of pressure are continually applied). As time passes a increases at an increasing rate. An example of a versus time is shown in Figure 6 for a particular pipe size, defect length, and applied pressure history. The crack which has an initial depth of 0.01 inch is shown to grow to a depth of 0.16 inch in 130 years at which point it is deep enough to cause failure at the MOP.

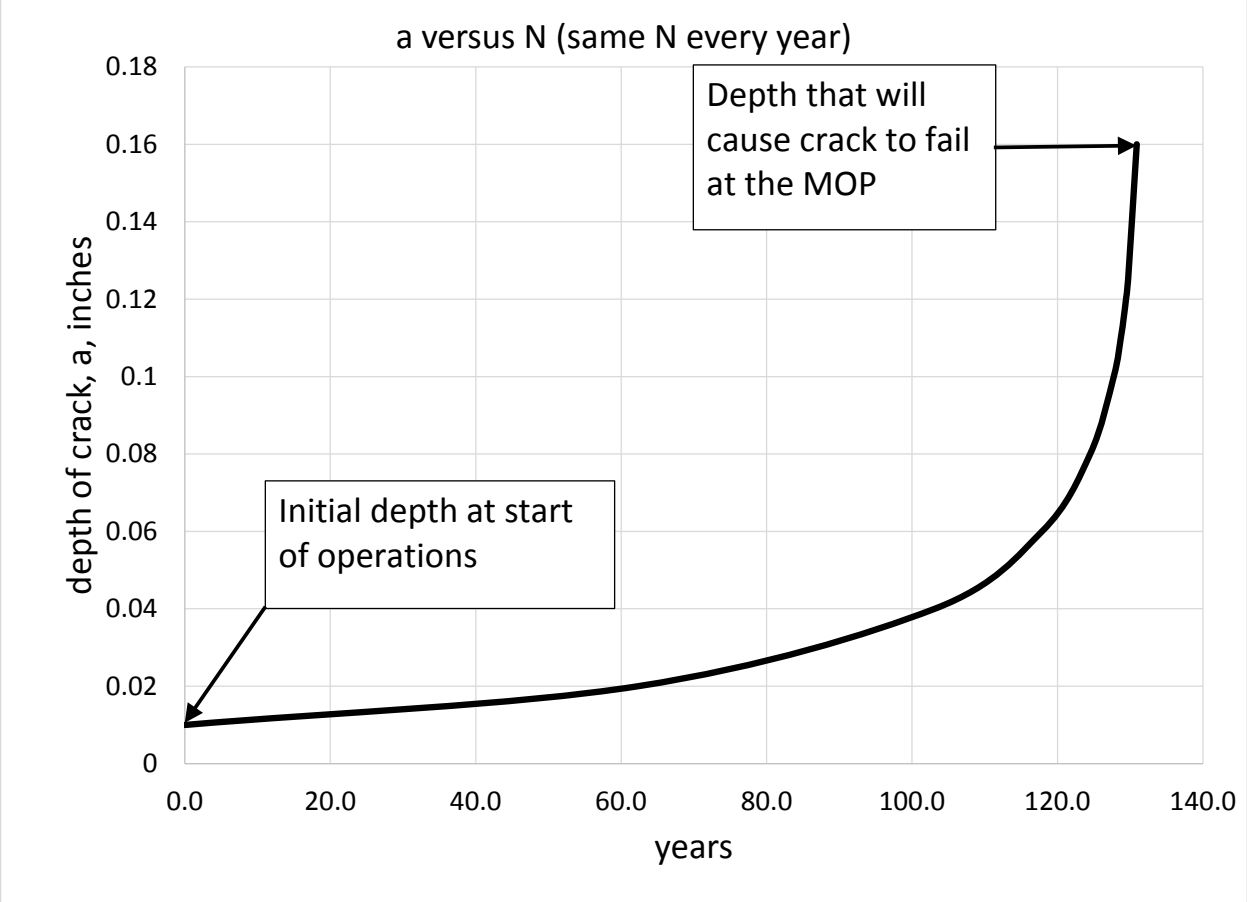


Figure 6. The Non-Constant Nature of Crack Growth from PCIF

The fact that the a crack begins to grow rapidly as it approaches the size that will fail at the MOP, means that mitigation in the form of a pressure test must either be applied as early as possible during the life of a crack or it will have to be repeated frequently if it is capable of finding only larger cracks. For example, if a pressure test applied to the crack represented in Figure 6, could eliminate a defect as shallow as 0.02 inch (the depth after 60 years of operation), the time to failure for any shallower crack would be at least 70 years, and a retest interval of 35 years (based on a factor of safety of 2) would be feasible. If, however, the shallowest crack that can be eliminated is 0.065 inch (the depth after 120 years of operation), the time to failure is only 10 years, and a retest interval of 5 years is required.

The number of cycles of a given level of stress needed for a crack with an initial depth, a_i, to grow to a final depth, a_f, is calculated by integrating Equation 5. Because of the complexity associated with most practical structures, closed-form integration of Equation 5 is usually not possible, and software designed for the purpose of numerical integration is generally used to perform the integration and calculate cycles to failure. The software models available for calculating cycles to failure also must be able to count cycles with variable stress ranges because most real loading situations involve load applications that vary with time. Various cycle-counting schemes are presented in ASTM 1049-85 (2011)e1, and the one that is often used in the analyses PCIF in pipelines is called "rainflow" counting.

Defects that remain after a pressure test can be no larger than the size that would have caused a test failure, so the maximum test pressure is used to establish the initial sizes of a representative sample of defects with different length-depth combinations that could have barely survived the test. The minimum time to failure for the worst-case defect modified by the factor of safety determines when retesting is needed to assure pipeline integrity.

The times to failure after a pressure test can be calculated via a Paris-law approach, provided that the user is able to supply the relevant data that includes pipe geometry and strength level, the relevant operating pressure-cycle spectrum and test pressure history for the segment being assessed. Other factors that affect the times to failures include material toughness, flow stress, and the crack growth rate constants associated with the Paris-law equation. These latter factors may not be known for each and every piece of pipe in a pipeline. However, a sensitivity analysis[xxix] shows that the analyst can expect to obtain conservative estimates of times to failure after a pressure test by assuming a toughness level corresponding to a full-size-equivalent Charpy upper-shelf energy level of 200 ft lb[18] and a flow stress equal to the minimum specified ultimate tensile strength of the base metal. Experience shows that the crack growth rate constants found in the API 579 standard for fitness-for-service are acceptable. Lastly, a factor of safety of 2 should be applied to the calculated times to failure to account for uncertainties in the material properties and the calculation process. The rational for the factor of safety of 2 is explained as follows in Reference XIX. "Typically, for the case of times to failure for defects that could have barely survived a hydrostatic test, a safety factor of 2 has been applied. That is, the recommended time for retesting is half the calculated time to failure for the defect with the shortest predicted time to failure. Our experience suggests that this time to failure is adequate and appropriate. The factor of safety of 2 in this context was suggested more than 20 years ago when this type of analysis was first being applied to scheduling retesting. It was chosen somewhat arbitrarily, but with the knowledge that ASME

[18] A high value of Charpy energy is used because the remaining defects after a test will be the larger than if a lower (and more realistic) value is used. The high value results in a shorter retest interval than would be the case if a low value were to be used.

pressure vessel design utilizes a factor of 2 on stress to avoid fatigue failures in service. The fact that ASME practice is to apply a factor of 20 on cycles to failure was not seen as a practical approach for fatigue crack growth in pipelines because the ASME practice applies to crack initiation not crack propagation. That is, fatigue life in the context of pressure vessel design envisions the cyclic life of a defect-free structure where most of the fatigue life involves the initiation of a crack. It is believed that the factor of safety of 20 was instituted to account for the possibility that an as-built structure might not in fact be defect-free. In contrast, the fatigue-life prediction method for pipelines is based on a known initial defect size, and the uncertainty involved in the calculation is believed to be much more limited."

In using fatigue analysis to calculate the times to failure after a pressure test, it must be assumed that defects could exist anywhere along the pipeline that are severe enough to have failure pressures no higher than that of the test pressure. This means that the analyst may have to calculate times to failure for multiple points along the pipeline taking account of the test level applied at each location, the wall thickness at each location, the effect of the hydraulic gradient on the pressure cycles at each location, and the effect of elevation on the static head at each location.

The study described in Reference XXIV further showed that the calculated times to failure after a pressure test increase exponentially with increasing test-pressure-to-operating-pressure ratio. Therefore, the operator can maximize the length of time between retests by utilizing the highest feasible test pressure that will not cause significant permanent expansion of pipe or an intolerable number of test failures. In absolute terms, the higher the test stress relative to the specified minimum yield strength of the pipe, the smaller the remaining defects will be. Smaller remaining defects mean longer times to failure after the test. For that reason, for a pipeline that is operated at maximum stress levels below 72% of SMYS, the test-pressure-to-operating-pressure ratio must be greater than that applied on a pipeline that operates at 72% of SMYS to achieve the same time to failure as that for the pipeline that operates at 72% of SMYS. This was illustrated previously for defects that have constant growth rates by the comparisons of data in Tables 12 and 13. This point is even more critical for defects that have non-constant growth rates such as PCIF. In particular, pipelines operated at stress levels as low as 30 to 50% of SMYS may be exposed to PCIF if they have only been pressure tested to levels of 1.25 times MOP or less. For this reason, it is advisable to carry out fatigue analysis on all pipelines that are operated at stress levels above 30% of SMYS, even natural gas transmission pipelines. The analysis may show that retesting is not required within the useful life of the pipeline, but it is important to know what the fatigue life of a pipeline is.

Lastly, once a satisfactory test has been achieved and a retest interval has been calculated, future pressure tests should be made at the same target test pressure level. Otherwise, it will be necessary to change the retest interval.

Spike Testing

A spike test refers to a pressure test in which the target maximum test pressure exceeds the minimum test pressure established by the operator for a particular pipeline (such as the test level required by 49 CFR 192 or 49 CFR 195), but that maximum pressure is held no longer than about 30 minutes after which the pressure level can be reduced to the level established by the operator for completion of the required hold times. The spike test, being at a higher pressure than the established test pressure, serves as the verification of integrity of the pipeline. The spike test pressure establishes the effective test-pressure-to-operating-pressure ratio for calculating remaining defect sizes and retest intervals.

The concept of spike testing is not new. Fessler[xxx] in 1979 was suggesting that a pressure test of 100 to 110% of SMYS held for only a few minutes followed by leak testing at a lower pressure could be effective for assessing a pipeline affected by SCC. Leis[xxxi] in 1992 also advocated similar testing on the basis that the most critical defects are removed within the first hour of a pressure test. In 2004 "TTO6" a special report on spike hydrostatic testing was prepared for the Research and Special Programs Administration[19] of the U.S. Department of Transportation. Most recently, Rosenfeld[xxxii] has discussed why and when spike testing should be used and when it may not be appropriate. The following is quoted from his paper. The phrase "standard test level" as used by Rosenfeld is assumed to mean a regulatory-required test to a minimum pressure level of 1.25 times MOP or MAOP.

"1. Spike testing is beneficial and therefore recommended in certain specific circumstances, namely:

a. Where crack-like defects such as SCC, selective corrosion of ERW seams, bond line defects in older vintage ERW seams, and seam fatigue cracks are expected to exist based on evidence from inspections, failures; or consideration of pipeline integrity threats;

b. Where it is desired to increase the retest interval for time-dependent flaws, particularly in high-stress pipelines; or

c. Where documentation is unable to confirm the attributes of the pipe or is unable to confirm that a prior hydrostatic test has occurred.

2. Spike testing is neither necessary nor harmful in the following situations:

[19] The Research and Special Programs Administration (RSPA) was the predecessor Federal agency to PHMSA.

a. Where the purpose of the test is to demonstrate the strength of the pipe where crack-like defects are not expected to be present;

b. Where the standard test margin is at least 1.4;

c. Where the operating stress is below 40% of SMYS; or

d. where the pipe being tested is new and of known good quality.

3. Spike testing to higher than the standard test level would be inadvisable in a limited set of specific circumstances, including:

a. Where the spike test pressure would exceed the mill test pressure or damage the pipe, particularly pipe susceptible to manufacturing defects in seams;

b. Where the spike test pressure would exceed the recommended maximum test pressure of components such as flanges or valves;

c. Where the margin above the spike test pressure could be insufficient to prevent excessive stress due to fluid thermal expansion effects during the test;

d. Where large elevation changes must be accommodated during testing; or

e. Where pneumatic testing is practiced."

Although Rosenfeld's suggested criteria for when to apply spike testing are generally sound, operators may want to consider the following:

- When a spike test cannot be at a sufficient pressure level, lowering the MOP or MOAP is an option.
- Not everyone agrees that spike testing is harmful when conducted at a pressure level in excess of the manufacturer's test level. It is likely that a test pressure above the manufacturer's test pressure will cause failures of seam manufacturing defects in older-vintage line pipe that has never been previously tested to a level in excess of the pressure reached in the manufacturer's test. However, such failures will tend to enhance the integrity of the pipeline because the remaining defects will be smaller than they otherwise would have been if the pressure in the manufacturer's test had not been exceeded.

As an example of a spike test, a pipeline operator might choose to do the following. In addition to the test required by the regulations for a hazardous liquid pipeline (a minimum level of 1.25 times the MOP for 4 hours followed by a test to 1.1 times the MOP for an additional 4 hours - a "Subpart E test"), the operator could elect to begin the test by pressurizing the pipeline to 1.39 times MOP, holding that pressure for the first 30 minutes of the first 4-hour hold period. After

this "spike test" the pressure would be lowered to 1.25 times the MOP for the remainder of the first 4-hour test period. The rationale for the spike test is that it eliminates or proves the absence of defects that would be expected to remain in the pipeline after a test to only 1.25 times the MOP. The hold period for the spike test is intentionally kept short to minimize the growth of any defects that are too small to fail. This rationale is explained in more detail in Reference XXIII (TTO6). The spike test, if conducted at a pressure more than 10% above the 1.25-times-MOP test level, virtually assures that no surviving defects will grow during the hold period at 1.25 times MOP while leak-tightness is being assessed.

Anticipating Test Failures

One of the drawbacks to pressure testing is the risk of ruptures and leaks occurring during the test. Such occurrences can significantly lengthen the time that the pipeline must be out of service, and numerous test failures often involve occurrences of pressure reversals. The number of test failures is likely to increase as the target test pressure level is increased. While a high-test-pressure-to-operating-pressure ratio is desirable, attempting to reach a relatively high target test pressure may come at the price of large numbers of test failures. Once the failures have occurred, and the target level has been achieved, the operator can confidently use that test pressure level to predict a retest interval.

Before beginning a pressure test, a pipeline operator should establish a target spike test pressure based on achieving an appropriate test-pressure-to-operating-pressure ratio to assure a desired re-assessment interval. As the pressure level in the test section is raised toward the target test pressure, test failures may begin to take place. Experience[xix] has shown that once test failures start to occur, the number of test failures tends to increase exponentially with increasing pressure and that some failures will occur as pressure reversals. Reference XIX discusses actual cases in which the failure pressure levels of the first few failures tended to establish a trend. The trend could then have been used to predict the likely number of failures that would occur in attaining the target test pressure level. The cases examined showed that the method was not highly accurate, but nevertheless, it could be useful in deciding whether or not to continue increasing the test pressure. If a decision is made to accept a lower final spike test pressure, the operator should be aware that the decision may result in a much shorter re-assessment interval.

Test Medium

In most cases water is chosen as the test medium for pressure tests of existing pipelines. There are two significant advantages to using water instead of a pneumatic medium (air, an inert gas, or natural gas). First, the use of water is much safer than a pneumatic medium because of the much lower energy release rate in the event of a failure. Fractures will not propagate when a failure occurs with water whereas fractures could be lengthy with a

pneumatic medium, and a fire or explosion could result if natural gas is used as the medium. It should also be noted that pressurized air can be hazardous in a pipeline if a residual film of liquid petroleum or petroleum product is present and an ignition source exists. Second, the detection of leaks is much easier with water than with a gas because of the much higher rate of pressure change with loss of test water compared to that with the loss of the test gas.

Using water as the test medium is also preferable to using liquid petroleum product in a liquid line. In the event of a test failure, the loss of the liquid petroleum product creates the risk of fire, explosion, and/or significant environmental damage.

In-Line Inspection

It is often possible to demonstrate the integrity of a pipeline segment via in-line inspection. Conventional means of in-line inspection involve inserting an appropriate inspection device into the pipeline while it remains in service, pushing the device through the pipeline with the shipped product, and recovering the device so that the data acquired as the device traveled through the pipeline can be analyzed. Depending on the type of device selected, the operator can inspect the pipeline segment for corrosion-caused metal loss, crack-like defects, geometric irregularities (e.g., dents, buckles, appurtenances), or changes in alignment due to settlement or other movement. In the context of repair/replace considerations for pre-regulation pipe, identifying and characterizing corrosion-caused metal loss and crack-like defects are of primary interest.

Ideally, anomalies can be identified by ILI and their locations and sizes (length and depth) can be determined. Also, in an ideal situation, the failure pressure level of each anomaly can be calculated, the time to failure for each anomaly can be predicted, and a remedial response can be undertaken in a timely manner for each anomaly based on its predicted time to failure modified by the factor of safety. In reality, neither of these ideal situations can be fully achieved because occasionally, defects are incorrectly identified as to type and because frequently, there are measurement errors. To better understand the significance of such errors, it is desirable for both ILI vendors and in-the-ditch NDE technicians to define the possible variations or errors in their measurements. Also, it is desirable for both the ILI vendors and the in-the-ditch NDE technicians to coordination with one another to optimize the interpretation of both the types and sizes of the identified defects.

Typically, for corrosion-caused metal loss and crack-like defects, an ILI service vendor analyzes the data and produces a list of anomalies indicating the location, clock-position, type, length, and depth of each anomaly. The list may also include a failure pressure level for each anomaly based on a failure stress prediction model, the relevant material properties (including fracture toughness if the anomaly is crack-like in nature), and the length and depth of the anomaly.

ILI for Corrosion-Caused Metal Loss

ILI technology for finding and characterizing corrosion-caused metal loss, either from external corrosion or from internal corrosion, has been proven effective by many years of experience. Pipeline operators can rely on the results of either magnetic-flux leakage or ultrasonic wall thickness tools to find and characterize metal loss with a high degree of confidence.[20] Failure stress prediction models for metal loss anomalies have been thoroughly validated[xxxiii]. Statistical analysis techniques are available to rank anomalies by severity and to predict re-assessment intervals[xxxiv]. Criteria for responding to metal loss anomalies in a timely manner have been incorporated into pipeline industry standards such as ASME B31.8S[xxxv] and API RP 1160[xxxvi]. With these tools, pipeline operators can successfully manage the threat of failure from corrosion-caused metal loss using ILI. Thus, repair of a pipeline affected by corrosion-caused metal loss can be carried out on a continuing basis for the long term by relying on ILI. Replacement of a piggable pipeline because of corrosion-caused metal loss likely would be considered if the cost of the re-assessments and repair responses became higher than the cost of replacement.

ILI for Crack-Like Defects

ILI technology for finding and characterizing crack-like defects exists and continues to evolve. At the current time three ILI crack-detection technologies exist. These are: Circumferentially-oriented magnetic flux leakage (CMFL), ultrasonic angle-beam crack detection (UTCD), and Electromagnetic Acoustic Transducer (EMAT). Both CMFL tools and the EMAT tools can be run in natural gas transmission pipelines and hazardous liquid pipelines. The UTCD tools require liquid coupling between the pipe wall and the transducers. Such coupling is achieved easily in pipelines filled with a liquid hydrocarbon (Applies to crude oil and most refined products. Such tools may not be effective in HVLs.) However, the only way a UTCD tool can be used in a natural gas pipeline is to introduce a slug of liquid to surround the tool at all times. The latter requirement is difficult to satisfy in most natural gas pipelines, so the UTCD tools tend to be used mostly for inspecting hazardous liquid pipelines.

As in the case of ILI for corrosion-caused metal loss, pipeline operators respond to lists of crack-like anomalies received from tool vendors by excavating a number of anomalies to verify the accuracy of the results. Unlike in the case of ILI for corrosion-caused metal loss where the depths and lengths of the exposed anomalies can be measured directly, the operator in the case of a crack-tool run must rely on non-destructive examination (NDE) to assess the

[20] Two possible exceptions are "narrow axial external corrosion" and "selective seam weld corrosion". Because of their long, narrow configurations, ILI tools sometimes underestimate the amount of metal loss associated with these two phenomena. A special configuration of magnetic-flux leakage tool that produces a circumferentially-oriented magnetic field is likely to be a more effective tool than a normal wall-thickness-measuring tool for characterizing anomalies associated with either of these two phenomena.

anomalies once they are excavated. The NDE usually consists of using magnetic particle examination to locate all crack-like defects at the OD surface and hand-held ultrasonic angle-beam inspection or phase-array ultrasonic inspection to assess the lengths and depths of the cracks. These "in-the-ditch" techniques assist the operator in verifying the accuracy of the ILI tools, however, these techniques are subject to errors as well. The operator decides on the basis of the verification digs how many more excavations are needed to assess cracks that appear to be significant based on the failure pressures calculated using the ILI-predicted defect dimensions or from the defect dimensions alone. Because the behavior of a crack-like defect typically depends on the toughness of the material, a representative value of toughness must be acquired or assumed in order to calculate failure pressure. If crack-like defects in the bond line of a LF-ERW material are the target, it may be prudent to use a brittle fracture criterion such as the Newman/Raju equations and assume a toughness corresponding to a Charpy V-notch energy of 1 ft-lb[21] (A fracture toughness of 9.4 ksi-root-inch via the Barsom and Rolfe equation). Values this low or lower have been inferred from full-scale burst tests. The anomalies for the "dig" list can be chosen based on a calculated value of failure pressure or based on other information provided by the vendor such as the length, depth, or type of anomaly. Anomalies on the dig list are then excavated, examined, and repaired if necessary.

The track records of the three types of tools mentioned above from the standpoint of their ability to locate and satisfactorily characterize defects in or adjacent to ERW and flash-welded seams were recently reviewed[xxxvii]. Thirteen tool-run cases involving 741 miles of pipe were reviewed, nine involving UTCD tools, three involving CMFL tools (without the enhanced data analysis developed by Kinder Morgan[xxxviii]), and one involving an EMAT tool[22]. Of the 13 cases examined, it was reported that none of the runs provided full confidence in the seam integrity of the assessed segment. In most of the cases the agreement between the ILI results and field NDE was not particularly good. Where anomalies were cut out and examined, inaccuracies in both the ILI results and the field NDE were found. Moreover, in some cases anomalies were missed by the ILI that were larger than the stated detection thresholds of the technologies. Aside from the thirteen cases it was also pointed out that three in-service pipeline failures caused by ERW seam anomalies occurred at normal operating pressures within two years after the pipelines had been inspected by means of ILI crack-detection tools. One of these cases involved the use of a UTCD tool. The other two cases involved the use of both a UTCD tool and a CMFL tool. In these cases the tools either altogether missed the defect that caused the failure or mischaracterized the defect as a non-injurious feature.

[21] The minimum value one can obtain from an actual Charpy test is generally 2 to 3 ft lb. That is because energy is required to move the broken pieces. Lower values are sometimes inferred by back-calculation from the results of a full-scale burst test of a flawed pipe.
[22] It should be noted that the EMAT tool was run for the primary purpose of assessing the pipeline for SCC. The vendor also reported finding some ERW seam anomalies, but the dimensions of those anomalies were not provided.

The capabilities of UTCD tools as demonstrated in two particular situations were assessed in a 2008 paper by Phillips and Maier[xxxix]. In the first situation, UTCD data from a seam-integrity assessment of a pipeline comprised of LF-ERW pipe was analyzed. In the second situation, UTCD data for several runs of small-diameter pipe were used to assess for SCC. The authors of Reference XXXV suggest that responding to cracks detected by UTCD ILI is similar to responding to corrosion-caused metal loss detected by magnetic flux leakage ILI and ultrasonic wall thickness ILI except that there may be less certainty in the case of crack detection. In the first place, the behavior of a crack-like defect is affected by material toughness (which is often unknown) whereas the behavior of a metal loss defect depends only on the strength of the material which can be approximated based on the grade of the material. Secondly, the extent of external corrosion-caused metal loss can be seen visually and measured directly and the extent of internal corrosion-caused metal loss can be determined by ultrasonic thickness measurements, whereas the extent of a crack can only be assessed non-destructively by angle beam ultrasonic transducers or eddy-current methods. The latter measurements are prone to be less accurate than measurements of wall thickness. Thirdly, while the discrete maximum depth of each metal loss anomaly is given by a metal loss tool, depth ranges rather than discrete depths are given by the UTCD tool for each anomaly (e.g., less than 0.04 inch, 0.04 inch to 0.08 inch, etc. or less than 12.5% of wall thickness, 12.5% to 25% of the wall thickness, etc.). Lastly, cracking is generally considered to be more of an integrity threat than metal loss because of the tendency of sharp cracks to extend under load from ductile tearing or sudden brittle fracture.

The authors of Reference XXXV assert that the investigations of anomalies found by the UTCD tool in ERW seams help to build confidence in the use of the tool for managing ERW seam integrity. It is important to note that they did not claim that the use of the UTCD tool for ERW seam integrity assessment gives as much confidence as a hydrostatic test. A large amount of scatter was seen in the comparison of ILI-reported depths and those reported by field-NDE. No data on the veracity of the field-NDE technique were presented. The authors noted the existence of "false negatives", that is, anomalies found upon excavation that were not indicated by the tool. All of these were said to be relatively shallow, though some had depths exceeding the vendor's stated depth detection threshold.

Regarding the pipelines where a UTCD tool was used to detect SCC, the authors of Reference XXXV found that anomalies indicated by the tool to be "crack fields" most often turned out to be SCC colonies. False negatives, some of which had NDE-determined depths greater than the depth detection threshold of the tool were found, and the comparison of ILI-reported depths and those reported by field-NDE showed considerable scatter. No data on the veracity of the field-NDE technique were presented.

A recent paper on EMAT technology[xl] suggests that EMAT technology is improving rapidly with respect to the detection and characterization of SCC. According to the authors, EMAT ILI can be used in place of a hydrostatic test for assessment of a pipeline for SCC provided that an EMAT tool run has been thoroughly validated by means of field NDE and that the pipeline has survived a confirmatory hydrostatic test with no failures from SCC. They noted, however, that the same cannot be said for the use of EMAT ILI for ERW seam defects. They assert that more work is needed on pipelines containing ERW seam defects before it can be considered prudent to substitute an EMAT ILI for a hydrostatic test to assess seam integrity in an ERW pipeline. Lastly, they acknowledge that field NDE involves uncertainties, and that errors due to NDE will add to the errors associated with the EMAT ILI itself with the total error being equal to the square root of the sum of the squares of the tool error and the NDE error.

ILI for Dents

ILI tools exist for characterizing dents, and operators are required to use such tools to locate dents in high-consequence areas. However, as mentioned previously, dents and mechanical damage defects are unlikely to cause an operator to consider replacing a pipeline.

ILI for Pipe Body Hard Spots

An MFL tool which has been specifically designed to identify residual magnetism can be used to locate pipe body hard spots. This was noted by Groeneveld in Reference 2, and it remains a viable technique for finding pipe body hard spots. Once hard spots have been located, they can be excavated and the pipe containing the hard spot can be removed. Alternatively, installing a steel reinforcing sleeve ("Type A" sleeve) or a pressure containing sleeve ("Type B" sleeve) over a hard spot has been shown to shield the pipe from cathodic protection current, thus eliminating the source of atomic hydrogen that might cause the hard spot to crack. Also, either type of sleeve prevents failure in the event that the hard spot cracks. Unfortunately, no ILI tool has been found that can reliably identify the presence of a hard heat-affected zone adjacent to an ERW seam. Mitigation of the HSC threat to the latter is discussed in a subsequent section of these guidelines.

Influence of Failure Stress Prediction Capabilities on Use of ILI-Crack Detection Tools

From the standpoint of cracks in the base metal of most line pipe materials, the failure stress levels of longitudinally-oriented crack-like defects can be predicted by any of the well-known failure stress prediction models mentioned earlier (References VI through X) if depths and lengths of the anomalies are accurately characterized and the fracture toughness of the material is known. The adequacy of failure stress prediction in base metal material follows from empirical observations that cracks in the base metal tend to fail in a ductile manner. As such, the level of fracture toughness is relatively unimportant. One can make a conservative

assessment in most such cases by assuming a material toughness equivalent to a full-size-equivalent Charpy upper shelf energy of 15 ft lb. A toughness level corresponding to a full-size-equivalent Charpy upper shelf energy level of 15 ft lb could be an appropriate value because that is about the minimum value one can expect for the base metal of a line pipe material manufactured prior to 1980.

Unfortunately, the ability to make failure stress predictions for anomalies in and adjacent to LF ERW, DC-ERW, and flash-welded seams is difficult. A recent evaluation of failure stress prediction methods[xli] showed that the Modified LnSec model[x] gave unreliable predictions of failure stress for defects in the seams of these materials because the fracture toughness in these seams was highly variable and because some of the defects (in particular, defects in the bond line) failed in a brittle manner. This work showed that conservative estimates of failure stress can be made using the Newman/Raju model[xi] if a very low fracture toughness is assumed (for example, a Charpy energy of 1 ft-lb corresponding to a fracture toughness of 9.4 ksi-root-inch via the Barsom and Rolfe equation)[23]. However, the use of this model with a low fracture toughness would likely result in predictions of low failure stress for most if not all of the anomalies identified by an ILI crack-detection tool. That would necessitate excavating and examining almost every anomaly even though many of the anomalies would turn out to be non-injurious. Therefore, the selection of ERW seam anomalies for examination may have to be based on criteria other than predicted failure stress. The appropriate parameters for anomaly selection should include length, depth, and location of the anomaly (i.e., in the bond line, adjacent to but not in the bond line). It is questionable whether or not the current ILI crack-detection technologies are capable of revealing whether or not a crack near an ERW seam is in the bond line or the heat-affected zone.

Calculating Re-Assessment Intervals for Integrity Assessment by ILI

As in the case of mitigation of time-dependent threats via pressure testing, mitigation by means of ILI involves crack-growth analysis to predict re-assessment intervals. The analysis involves knowing the operating pressure spectrum, the initial sizes of defects, the pipe geometry and material properties (including fracture toughness if crack-like defects are involved), applying representative crack growth rates to "grow" the defects, and determining the time required to cause the defects to attain (final) sizes that will cause a failure at the maximum operating pressure (MOP) of the pipeline. A factor of safety is then applied to the time to failure so that a response is made well before any growing defect can reach a size that would cause failure at

[23] The use of the Newman/Raju empirical equations by themselves could lead to non-conservative predictions of failure stress if the toughness is not extremely low and the failure stresses of the defects being assessed are higher than about 40% of the flow stress of the material. In cases where the material is not extremely brittle and/or the failure stresses are higher than about 40% of the flow stress, an API 579-Level II or Level III analysis should be conducted to include the possible contribution of elastic-plastic behavior.

the MOP. Where ILI is used as the sole means of periodic integrity verification, analytical tools must be available to assess the effects of identified defects on pipeline integrity or the pipeline operator must be willing and able to directly examine and verify the nature the identified anomalies.

The initial sizes of defects are established from the ILI data considering tool error. The pipe geometry and nominal strength levels (e.g., SMYS) are usually known. The rates of growth can be based on the operator's experience or taken from standards or technical documents. The final defect sizes for failure at the MOP must be calculated based on a credible failure stress prediction model. As noted above fracture toughness may not matter that much if the material can be expected to behave in a ductile manner. In the case of assessment by ILI (unlike in the case of a hydrostatic test), it is prudent to assume a low value of toughness because the lower the toughness used in the analysis is, the lower the failure stress of a given defect will be and the shorter will be the predicted times to failure.

Also, unlike in the case of a hydrostatic test, it is prudent to assume a low value of flow stress because the lower the flow stress used in the analysis is, the shorter will be the predicted times to failure after the test. An appropriate level of flow stress for the vintages of materials that are likely candidates for replacement would be SMYS+10,000 psi.

As in the case involving predicting times to failure from PCIF after a hydrostatic testing, the crack growth rate constants found in the API 579 standard for fitness-for-service are acceptable for use in calculating times to failure after a seam assessment via ILI.

In using fatigue analysis to calculate the time to failure from PCIF after a seam integrity assessment via ILI, the pipeline operator will know where defects that could grow by fatigue are located and should also be able to tell within certain bounds, the lengths and depths of the defects. Since the locations of the anomalies are known in the case of assessment by ILI, it is simply a matter of adjusting the pressure-cycle spectrum from the upstream and active downstream stations to account for the distance along the hydraulic gradient. An analysis should be made for all significant anomalies so that the times to failure will be known. The operator will then be able to prioritize the anomalies by their times to failure and respond in a timely manner to remediate them before they grow to a size that would cause an in-service failure.

Assessment of ERW seam integrity using a reliable ILI crack-detection tool should permit longer intervals between re-assessments than is the case with repeated hydrostatic testing because an ILI tool should be able to find much smaller defects than those that can survive a hydrostatic test to the highest feasible test stress levels.

Direct Assessment

Another means of verifying pipeline integrity from the standpoint of specific threats is "direct assessment". There are three types of direct assessment intended to address each of the following threats:

- External corrosion: External corrosion direct assessment (ECDA)
- Internal corrosion: Internal corrosion direct assessment (ICDA)
- Stress corrosion cracking: Stress corrosion cracking direct assessment (SCCDA)

Direct assessment for one or more of these specific threats can be used in place of hydrostatic testing or ILI if neither of the latter is applicable to a specific segment of pipe. An example of a natural gas transmission pipeline where conducting hydrostatic testing is not feasible is a single-feed pipeline serving a community where taking the line out of service and cutting off customers cannot be tolerated. In many cases, such pipelines also are operated at relatively low pressures and flow rates, so that pushing a pig for ILI purposes may not be feasible. It is noted that even if all three types of direct assessment are applied to a particular pipeline, other threats such as PCIF, if they existed, would still have to be addressed by hydrostatic testing or ILI. So, direct assessment as the sole means of integrity assessment is typically applied to natural gas transmission pipelines where the threat of PCIF occurring is insignificant and where it is not feasible to carry out ILI or hydrostatic testing.

ECDA

A pipeline operator wishing to use ECDA to address the threat of external corrosion should first consult ANSI/NACE SP0502-2008, "Standard Practice – Pipeline External Corrosion Direct Assessment Methodology", the current version of this standard that is accepted by 49 CFR 192 and 49 CFR 195. This standard explains the ECDA process, shows how to apply it, and points out its limitations. Basically, the methodology involves four steps. The four steps consist of gathering and integrating data on the pipeline segment to which ECDA will be applied (pre-assessment), conducting various types of above-ground electrical surveys (indirect inspections) to identify areas where external corrosion may be occurring or could occur, examining a sufficient number of such locations by excavating the pipe (direct examinations) to examine its condition, and assessing the effectiveness of the process as a means of mitigating external corrosion (post-assessment). At each excavation relevant measurements (such as dimensions of metal loss and soil resistivity) are made, observations (such as soil type and coating condition) are noted, and repairs are made where necessary. The data obtained from the examinations are used to define and execute mitigative actions, to predict the time interval for the next ECDA, and to assess the adequacy of the ECDA process with respect to addressing the threat of external corrosion. Operators seeking additional guidance for applying ECDA to a

pipeline segment may find it advantageous to review a systematic approach utilized by one operator[xlii].

Some of the inherent limitations of ECDA are that it may not be very effective in locating potentially corroding areas on cased pipe, on pipe located in frozen soil, on bare or poorly coated pipe, and on pipelines with high-dielectric coatings that become disbonded. Another limitation is that the criteria for interpreting the indirect measurements and for prioritizing responses are somewhat subjective and may vary from operator to operator. A recent study sponsored by PHMSA[xliii] has resulted in improved standards for interpreting indirect measurements and for prioritizing responses based on considering the type of soil involved with a particular measurement location.

No data were found in the public domain that could be used to assess the effectiveness of ECDA as an integrity assessment method for addressing the threat of external corrosion. However, a pipeline operator who uses ECDA extensively and repeatedly on a particular segment of a pipeline with uniform parameters (diameter, wall thickness, type of pipe, type of coating, type of cathodic protection, type of soil, etc.) can acquire a useful database that will tend to indicate whether or not ECDA is effective as an integrity assessment tool for the threat of external corrosion for that segment. Most importantly, ECDA will be proven ineffective if in-service leaks and ruptures from external corrosion continue to occur. The fact that failures do not occur after successive ECDAs is encouraging, but that fact alone may not be sufficient to prove effectiveness. The level of effectiveness depends at least to some extent on the following types of data:

- The number of excavations where corrosion was found when excavations were made because of the indirect measurements indicating the probable existence of corrosion (true positive results)
- The number of excavations where no corrosion was found when excavations were made because of the indirect measurements indicating the existence of corrosion (false positive results)
- The number of randomly selected excavations where corrosion was found but where the indirect measurements gave no indication of corrosion taking place (false negative results)
- The number of randomly selected excavations where no corrosion was found and where the indirect measurements gave no indication of corrosion taking place (true negative results)

These data can be represented symbolically as follows:

True Positives ⇒	*CI/CF*	*CI/CNF*	⇐	False Positives
False Negatives ⇒	*CNI/CF*	*CNI/CNF*	⇐	True Negatives

where:

CI stands for corrosion indicated by indirect measurements

CNI stands for corrosion not indicated by indirect measurement

CF stands for corrosion found upon excavation

CNF stands for corrosion not found upon excavation

It has been suggested previously[xliv,xlv] that these data can be analyzed by means of Bayes Theorem to establish the probability that external corrosion could be occurring and not be detected. The smaller that probability, the more effective is the ECDA program. In terms of the symbols above, Bayes Theorem says that the probability of corrosion being found upon excavation given that corrosion was not indicated by indirect measurements is given as follows:

$$P(CF \mid CNI) = \frac{P(CNI|CF)P(CF)}{P(CNI|CF)P(CF)+P(CNI|CNF)P(CNF)} \qquad \textbf{Equation 7}$$

where:

$P(CF \mid CNI)$ is the probability of finding corrosion given that corrosion is not indicated by indirect measurements

$P(CNI \mid CF)$ is the probability of corrosion not being indicated given that corrosion exists

$P(CNI \mid CNF)$ is the probability of corrosion not being indicated given that corrosion does not exist

$P(CF)$ is the probability of finding corrosion upon random excavation

$P(CNF)$ is the probability of not finding corrosion upon random excavation

Ideally, to get *P* (*CF*) and *P* (*CNF*) the operator must randomly select 20 to 30 locations for excavation without being influenced by any indirect measurements. In practice, the operator may have historical leak data or bell hole examinations that allow an estimation of *P* (*CF*). Alternatively, the operator may be able to excavate many randomly selected locations where indirect measurements gave no indications of corrosion during an ECDA. Then the probability

of corrosion, *P* (*CF*), can be assessed as the number of cases where corrosion was found divided by the total number of excavations at locations made where there were no indications from indirect measurements. *P* (*CNF*) is 1 – *P* (*CF*).

To see how measuring the effectiveness of ECDA works, consider the following examples. In the first example assume that the probability of finding corrosion anywhere along a segment, *P* (*CF*), and the probability of not finding corrosion, *P* (*CNF*), are to be determined by excavation at randomly selected locations where there are no indications of corrosion. An ECDA is conducted after which excavations are made to check the results including 20 excavations where there were no indications. The excavations where there were no indications reveal 2 locations out of these 20 where corrosion is found even though there was no indication of corrosion meaning that both *P* (*CF*) and $P(CNI \mid CF)$ are 2 in 20 or 0.1 and that *P* (*CNF*) and $P(CNI \mid CNF)$ are both 18 in 20 or 0.9. This example could represent a well-coated and well-protected pipeline. The effectiveness of the ECDA in terms of $P(CF \mid CNI)$ is

$$P(CF \mid CNI) = \frac{0.1 * 0.1}{0.1 * 0.1 + 0.9 * 0.9} = 0.012$$

In the second example assume that the probability of finding corrosion anywhere along a segment, *P* (*CF*) is 0.5 and that *P* (*CNF*) is 0.5 based on historical leak data. This example could represent a poorly-coated pipeline. An ECDA is conducted after which excavations are made to check the results including 20 excavations where there were no indications. The excavations where there were no indications reveal 4 locations out of these 20 where corrosion is found even though there was no indication of corrosion meaning that $P(CNI \mid CF)$ is 4 in 20 or 0.2 and $P(CNI \mid CNF)$ is 16 in 20 or 0.8. The effectiveness of the ECDA in the second case in terms of $P(CF \mid CNI)$ is

$$P(CF \mid CNI) = \frac{0.2 * 0.5}{0.2 * 0.5 + 0.8 * 0.5} = 0.2$$

The ECDA for the segment in the first case is more effective than the ECDA for the segment in the second case by a factor of 16.7 because the inherent probability of corrosion is lower and because there were fewer false negatives.

Calculations such of these can be viewed as aids in assessing the effectiveness of ECDA, but they should not be regarded as absolute criteria for evaluating an ECDA for a number of reasons. First, there is bound to be scatter in the data such as the number of false negatives that would be obtained from different sets of random excavations. Second, the criteria used for defining a false negative could vary from one operator to another. Some might consider finding minor metal loss at a location that had no indications from indirect measurements as not being significant and thus not a false negative. Third, different operators are likely to view indications

from indirect measurements differently because of the vague priority ranking criteria in NACE SP0502. The main value of pursuing such calculations is that it encourages an operator to make excavations at randomly selected locations where the indirect measurements show no indications. Conducting such excavations should be considered as a legitimate part of the expense associated with using ECDA as an integrity assessment method.

ICDA

Processes for conducting internal corrosion direct assessment (ICDA) are described in several NACE standard practices. These processes can be used to address the threat of internal corrosion to pipeline integrity. Mitigation of the threat consists of repairing pipe that is found to contain integrity-threatening amounts of internal corrosion-caused metal loss, instituting or enhancing preventative measures, and re-assessing integrity at appropriate intervals.

The ICDA standard applicable to natural gas transmission pipelines carrying "dry" gas is NACE 02087 *Internal Corrosion Direct Assessment of Gas Transmission Pipelines*. This standard is applicable to natural gas transmission lines that normally carry dry gas but may incur short term exposure to wet gas or liquid water as the result of upset conditions. The processes described in the standard involve detailed examinations of locations along a pipeline where an electrolyte such as water could accumulate. Fluid flow models and the actual profile of a pipeline are used to determine the most likely locations for water to accumulate. The condition of the remainder of the pipeline is then inferred from the nature of the metal loss at areas where water could accumulate. If the metal loss is severe, the operator may decide to investigate other areas of the pipeline. Repairs are made where necessary, the observed corrosion rates are used to determine when re-assessment is necessary, and the results of the ICDA are used to assess the effectiveness of the process.

The ICDA process applicable to natural gas transmission pipelines carrying "wet" gas is NACE SP0110-2010, Wet Gas Internal Corrosion Direct Assessment Methodology for Pipelines. This standard is to be used for natural gas transmission pipelines that carry natural gas containing water or hydrocarbon condensate.

The following two documents address conducting ICDA for hazardous liquid transmission pipelines. For liquid pipelines there is the added risk of internal corrosion being facilitated by sludge or other solids accumulating in low-flow locations in addition to water.

- NACE SP0208-2008, Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines
- NACE 07169 Internal Corrosion Direct Assessment Methodology for Liquid Petroleum Pipelines

As in the case of ECDA, one can use numerical calculation methods such as Bayes Theorem to assess the effectiveness of ICDA. The main requirement for such calculations is to conduct significant numbers of direct examinations of a segment at randomly selected locations where no indications from flow calculations or elevation changes would suggest the occurrence of internal corrosion.

SCCDA

NACE SP0204-2008 (formerly RP0204), Stress Corrosion Cracking (SCC) Direct Assessment Methodology presents guidelines for assessing the threat of stress corrosion cracking to pipeline integrity. Guidance is given for identifying segments of pipelines that may be susceptible to SCC, for selecting sites for excavating and examining locations along any given segment of a pipeline, for inspecting pipe after excavating it, and for the type of data that is to be collected at each site. Guidance is also given for mitigating SCC, for establishing re-assessment intervals, and for evaluating the effectiveness of the process.

Guidance for dealing with SCC may also be obtained from Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas STP-PT-011 – 2008" and ASME B31.8S.

As in the case of ECDA, one can use numerical calculations methods such as Bayes Theorem to assess the effectiveness of SCCDA. The main requirement for such calculations is to conduct significant numbers of direct examinations of a segment at randomly selected locations where no occurrences of SCC would be expected.

Mitigative Response for the HSC Threat to a Hard Heat-Affected Zone

On the basis of the known instances of failure, the threat of HSC developing in hard heat-affected zones of ERW pipe appears to be confined to X-Grades of ERW pipe made between 1947 and 1960 by one manufacturer, Youngstown Sheet and Tube Company. Three such HSC failures were documented in Youngstown pipe by Clark, et. al.[xlvi], and one of the authors of this guideline document has been involved in at least three investigations of failures from HSC in hard heat-affected zones, all involving ERW pipe made by Youngstown during the late 1940s. It is the experience of one of the authors of this guideline document that some but not all pieces of ERW pipe made by Youngstown during this period have the requisite high hardness level (at least Rockwell C35) for HSC to occur. Youngstown ERW pipe was made piece-by-piece from individual plates formed into cans for welding rather than continually from coil as with most other ERW manufacturers at the time. That means that each piece of Youngstown ERW pipe could have had a unique alloy content and post-weld heat treatment. Apparently, some pieces ended up with the requisite high hardness adjacent to the seam to be susceptible to HSC, while others ended up with hardness levels not susceptible to HSC. One can only verify

the hardness of the narrow heat-affected zone of any given piece of pipe by means of taking microhardness measurements on a metallographic section across the seam, an impractical means of locating the susceptible pieces during manufacturing let alone in an existing pipeline.

As has been noted previously herein, hydrostatic testing is not effective as a means of mitigating HSC, because neither the tendency for HSC to develop nor the rate of growth of HSC is predictable. Moreover, there is no known ILI technology that can reliably locate those pieces of pipe that might have a heat-affected-zone hardness sufficiently high to be susceptible to HSC. Therefore, mitigation of the HSC threat with regard to hard heat-affected zones consists of trying to minimize the generation of atomic hydrogen from cathodic protection. Atomic hydrogen can be generated at the surface of the pipe at an area of disbonded coating at a potential level of -0.85 volts relative to a copper, copper sulfate half-cell, the level considered by some to be sufficient to mitigate significant corrosion. The corrosion mitigative effect of cathodic protection increases as the potential level becomes more negative than -0.85, so it is a practical necessity to have some areas of a pipeline experiencing levels more negative than -0.85 to assure that all portions of the pipeline are experiencing the -0.85 level. As shown in Reference II, the amount of hydrogen generated increases exponentially as the potential level becomes more negative than -0.85. In some of the cases where HSC failures have occurred, it is known that the pipe-to-soil potential levels ranged from -1.3 to more negative levels. Thus, controlling the pipe-to-soil potential levels to values not greatly exceeding the level required for mitigation of corrosion is a means (and at this point in time, the only known means) of mitigating the threat of HSC failures in a pipeline comprised of Youngstown ERW pipe made between 1947 and 1960.

Mitigative Responses for Gas Distribution Systems

The substantial differences between natural gas distribution systems and natural gas transmission pipelines make it impractical simply to apply the integrity management requirements for transmission pipelines to distribution systems[xlvii]. In particular, the characteristics of most gas distribution systems (i.e., low operating pressures, sharp bends, numerous branch lines, multiple types of pipe materials and diameters, and direct connectivity to end users) preclude the use of pressure testing (other than in-service leak testing), ILI, and direct assessment for assessing pipe integrity. Furthermore, the significant diversity of the pipeline systems within the gas distribution industry renders the concept of establishing standard requirements for all integrity management circumstances impractical. Representatives that comprised the joint work/study groups that performed the research for the Integrity Management for Gas Distribution, Report of Phase 1 Investigations, concluded in December 2005, that the current pipeline safety regulations (49 CFR Part 192) did not convey the concept of a risk-based distribution integrity management process, and it would be appropriate to modify the regulations to include such a process for natural gas distribution systems.

Therefore, the joint work/study groups determined that it would be appropriate to require all distribution pipeline operators, regardless of size, to implement an integrity management program. In 2009, The Gas Piping Technology Committee (GPTC) released the Distribution Integrity Management Program (DIMP) guide[xlviii] with material intended to assist operators with development of a DIMP, and guidance on compliance with Federal Regulations contained in 49 CFR Part 192, Subpart P[xlix]. On August 2, 2011, in order to comply with Subpart P, gas distribution operators were required to develop and implement an integrity management program that included a written integrity management plan. This plan was required to contain procedures for developing and implementing the seven elements identified as the essential components of a DIMP. Collectively, these elements establish a program for distribution operators that should reasonably manage the integrity of their pipeline systems into the future. The seven elements of DIMP[24] are:

1. Knowledge
2. Identify threats
3. Evaluate and rank risk
4. Identify and implement measures to address risks
5. Measure performance, monitor results, and evaluate effectiveness
6. Periodic evaluation and improvement
7. Report results

While the GTPC guide does not imply the order in which these elements should be applied, it does stipulate that the operator needs to address each element in some way. The guide is intended to be just that, a guide. The authors of the guide caution that it does not anticipate all conditions that may be encountered, and it also does not restrict the operator from using other methods to comply with the DIMP regulations.

This report concentrates on the mitigative responses discussed in Section 6 of the DIMP guide, "Identify and implement measures to address risks". It will be clear that the mitigative responses previously discussed in relation to transmission pipeline systems (hydrostatic testing, ILI, and direct assessment) are not a part of the mitigative responses in the DIMP guide because they are impractical for distribution systems. ANSI/GPTC Z380, Guide for Gas Transmission and Distribution Piping Systems, Appendix G-192-8, Table 6.1 – Examples of Additional or Accelerated (A/A) Actions (occasionally referred to by PHMSA inspectors as risk reduction measures) provides guidance on possible A/A Actions, which can be taken to reduce the risks associated with distribution pipeline facilities, however the ultimate decision of which

[24] State regulations may have additional DIMP requirements more stringent than Federal DIMP codes in § 192.1007.

A/A Action(s) is/are most practical, reasonable, and economically feasible is left up to the operator. The operator may choose whether to implement some, all, or none of these actions. Some of the more common A/A Actions utilized by distribution system operators to address specific threats are discussed hereafter.

A/A (Additional or accelerated) Actions (Risk Mitigation Measures) for Specific Threats from Table 6.1 of ANSI/GPTC Guidance Appendix G-192-8

As noted earlier in the report, the threats to the integrity of a natural gas distribution system that could possibly be addressed by replacing a segment of pipe are external corrosion, internal corrosion, natural forces, and material or weld failure. Accordingly, the accelerated actions that an operator might take to mitigate these threats in order to delay or avoid replacement are discussed below.

External Corrosion

The A/A Actions discussed in this section pertain to bare steel pipe with or without cathodic protection (CP), wrapped steel pipe with or without CP, and Cast Iron pipe with external corrosion or graphitization issues.

Increase frequency of patrolling and leak surveys

Requirements for patrolling distribution systems and conducting leak surveys are established in 49 CFR 192.721 and 192.723. In accordance with 49 CFR 192.721(b)(1) and 192.721(b)(2), mains in places or on structures where anticipated physical movement or external loading could cause failure or leakage must be patrolled, in business districts, at intervals not exceeding 4-1/2 months, but at least four times each calendar year; and outside business districts, at intervals not exceeding 7-1/2 months, but at least twice each calendar year. Areas where physical movement or external loading is known to exist, such as known unstable bridge crossings or areas prone to landslides, should be patrolled in accordance with these intervals. Similarly, leakage surveys using detector equipment must be conducted in business districts, at intervals not exceeding 15 months, but at least once each calendar year to remain in compliance with 49 CFR 192.723(1), while outside business districts, they must be conducted as frequently as necessary, but at least once every 5 calendar years at intervals not exceeding 63 months to remain in compliance with 49 CFR 192.723(2). However, for cathodically unprotected distribution lines (e.g. bare steel) subject to 49 CFR 192.465(e) on which electrical surveys for corrosion are impractical, a leakage survey must be conducted at least once every 3 calendar years at intervals not exceeding 39 months.

Distribution operators should maintain records of all leaks experienced on their systems to allow leak trends to be monitored. This enables the operator to determine whether the leak issue is improving, worsening, or remaining the same. If the operator continues to experience an increased number of leaks per mile or leaks per thousand services, then another action should be implemented.

Replace, insert or rehab

Three other mitigative responses available to distribution pipeline operators are to replace the line, insert new pipe through the line (i.e. push or pull a new, smaller-diameter pipe through an existing, larger-diameter pipe), or rehab (i.e. repair) the line. These mitigative responses can be applied along the entirety of the line or only on specific portions of the line. Plastic pipe inserted through a steel main is an example of an insert type of replacement where the new, smaller-diameter pipe becomes the carrier for the gas, and the existing, larger-diameter pipe is abandoned. An operator may continue to rehab segments of pipe or insert new segments of pipe in problematic areas, as necessary, recognizing that at some point it might be more economically feasible to just replace the entire line.

Relocate

In instances along a pipeline, where active corrosion is a major issue, correcting cathodic protection issues is often the most feasible mitigative response. However, relocation may be appropriate under certain circumstances, as a last resort, where corrosion persists.

Provide hot spot protection (e.g., install anodes at anodic locations)

In areas where cathodic protection is used to mitigate corrosion, operators should monitor trends in the number of sacrificial anodes installed and the ability to maintain adequate cathodic protection levels. A cost-benefit type analysis could aid the operator in deciding whether continuing to replace anodes, adding additional anodes, relocation or replacement is the most appropriate mitigative response.

Correct cathodic protection deficiencies

In accordance with 49 CFR 192.465(a), which covers pipelines under cathodic protection, the levels of protection must generally be assessed at least once each calendar year, but with intervals not exceeding 15 months, to determine whether cathodic protection levels meet the requirements of 192.463. Operators shall take prompt remedial action to correct any cathodic protection deficiencies indicated by monitoring as required by 49 CFR 192.465(d). Other requirements for controlling external corrosion using cathodic protection are given in 49 CFR 192.463 to 192.473.

Internal Corrosion

Internal corrosion in a distribution system can arise in conjunction with condensation and water accumulation. When possible, the operator should inspect the interior surfaces of the piping for signs of internal corrosion and/or water accumulation. Water should be drained from the system, if found, and the segment should be cleaned out, if possible. If pitting is discovered, the severity needs to be assessed, and if leakage is imminent, it should be managed in an acceptable manner. If the product transported is corrosive, the operator would need to take action to manage the leaks along the line and to monitor the leak trends and institute appropriate mitigative action to reduce leakage.

Install pipe liner

Tight-fit (cured in-place[25]) type pipe liners are capable of being installed in cast iron pipelines as a mitigative response to leakage due to internal corrosion. When liners are properly installed, the threat of leakage to the pipeline is significantly reduced. This mitigation is only applicable if the existing pipe structure is strong enough to handle the stresses experienced by the line at the maximum operating pressure as the liner will not add any structural integrity to the line. CIP liners are also used as a repair techniques for external localized graphitization or to address bell/spigot joint leaks (typically due to internal drying from ultra dry and LNG gas).

Install moisture removal/control equipment and evaluate gas supply inputs / take corrective action with supplier

Moisture removal or control equipment, such as dehydration units, can be installed at pipeline gate stations to remove excess water from the gas entering the distribution system. While dehydration units are a viable option for moisture removal or control, the more common practice among distribution pipeline operators is to monitor the gas entering the system for quality issues such as H_2S, CO_2, and water, and take corrective action with the supplier, as necessary. Situations such as this are especially relevant in areas receiving natural gas from local shale areas where gas may not have been treated sufficiently or might be different from the natural gas the operator received previously from long haul pipelines.

Natural forces

Threats due to natural forces require A/A actions to counteract outside force/weather issues (e.g., earth movement, lightning, heavy rains/floods, temperature extremes, high winds)

[25] Operators should check with the applicable governing pipeline codes (Federal and State) to be sure cured in-place liners meet pipeline regulations for hazardous liquid or natural gas pipelines.

affecting a pipeline. These threats affect all types of pipe materials including steel, plastic, and cast iron. It is important to remember that these types of threats are situational (i.e. they all don't occur everywhere) and if the threat to the pipeline is local then the mitigative response will also remain local.

Relocate pipe from high risk locations

Relocation can be an effective form of mitigation to avoid high risk locations. For example, if a pipeline is currently running along a hillside with a history of soil erosion issues and landslides, the risk of these possible outside forces causing a failure in the line may outweigh the benefits, thus leading to the decision to relocate the pipeline out of this area. The economics of the situation along with the risks involved will drive the decision of whether relocation is a viable option.

Replace pipe in high risk locations

For many reasons, relocating a pipeline may not be possible, thus leaving the operator with the task of finding another way to protect the pipeline in the high risk location. Replacement could prove to be a worthwhile option to ensure the safety and integrity of the line, in which the operator could replace the segment of line in the high risk location with a pipeline designed to more suitably withstand the threats posed by natural forces in the area.

Install slip or expansion joints for earth movement

In areas where earth movement is an issue and relocating the pipe is not an option, it may be necessary to modify the existing pipeline, so as to allow slip or expansion joints to be installed to help the pipeline accommodate some of the earth movement which is known to occur in the area. Installing these components will help to mitigate at least some of the risk associated with this type of threat.

Install strain gauges on pipe

In known high risk locations where soil movement is prevalent, such as with mine subsidence, earthquakes, soil erosion or washouts, soil slumping (on hill sides), or sink holes, installing strain gauges along the pipeline allows operators to monitor their risk based on the stress and strain the pipe is experiencing. Monitoring natural forces in this manner allows operators to set stress and strain limits as a method of determining when to intervene and physically manipulate the line so as to reduce the stress/strain it is experiencing.

Expand the use of excess flow valves

Excess flow valves (EFV) are small, relatively inexpensive devices that can be installed on distribution service lines usually in or near the service tee connection to a main. They are manufactured to activate based on a desired flow rate (at a given system pressure). For example, such a valve might be manufactured to close at a flow rate of 500 SCF per hour at a pressure of 10 psig. At 60 psig operating pressure, the closure rate would be much higher. The closure rates of EFV's are not adjustable.

Installing EFV's on high risk service lines could provide a safeguard to prevent a hazardous situation should excavation damage, a severe leak, or an outside force incident occur downstream of the valve. These valves are very effective at shutting off the flow of gas through a service line if damage should occur to the line, and they won't allow gas to flow again until the damaged line is repaired. This prevents a large influx of gas from possibly entering an end user's residence or place of business should some type of damage to the distribution line occur downstream of the valve. Other benefits of installing this type of valve are that it allows first responder crews more time to evacuate the buildings or areas affected by a damaged distribution pipeline as well as preventing a large vapor cloud from quickly forming and possibly finding an ignition source.

Conduct leak survey after every significant earthquake or other event

Natural forces can create risk on a pipeline system, especially lines in unstable soil locations. It is good practice to perform leak surveys after any natural outside force event, such as a significant earthquake, a winter storm, repeated freeze/thaw occurrences (especially with respect to cast iron pipe), or any other type of severe weather event to confirm the event did not cause an integrity issue with the pipeline.

Material or weld failure

Threats due to material or weld failure may require A/A actions to respond to manufacturing defects and construction/workmanship defects that could affect the pipeline. These threats could potentially affect all types of pipe materials including steel, plastic, and associated piping components. It is important to keep in mind that these types of threats have the potential to exist anywhere in the pipeline, and if found, then trending the pipe material, manufacturer, installation date, installation contractor, and other pipe properties should be completed in an attempt to determine whether the issue is local or systemic.

Some of the A/A actions applicable to material or weld failures were already discussed in previous sections of this report (i.e. the External or Internal Corrosion, or Natural Forces sections). To avoid being repetitive, refer to the aforementioned sections for details on the

following A/A actions: increasing the frequency of leak surveys, repairing the line, or replacing the line. Each of these A/A actions is also acceptable to utilize with material or weld failure type threats. Other A/A actions, which can be utilized in mitigating material or weld failure threats are discussed in more detail below.

Revise construction procedures

If the evaluation of a failure indicates that it was caused by construction or workmanship defects, then it may be prudent to review the construction procedures to which company and contractor personnel must adhere, in order to determine whether modifications or changes to these procedures are necessary. If the outcome of this review indicates the existing procedures are adequate, then the issue might involve the construction oversight or the company or contractor personnel actually performing the work. If this is the case, site inspectors overseeing construction should receive further training to confirm their technical understanding of the company construction procedures, while historical construction records should be reviewed to investigate whether the company or contractor personnel that completed the work has any instances of poor performance in the past. Keeping historical records of site inspector and construction personnel performance will allow the pipeline operator to only utilize high performing personnel on future projects.

Revise material standards

If a failure is determined to have been caused by a material problem, then it might be necessary to revisit the material standards to which the pipeline was designed to verify the standards align with prudent engineering and/or generally accepted industry practice. If the material standards are verified to align with industry practice and specify appropriate materials, then some trending may be necessary to determine whether the material problem is widespread throughout the system or whether it is isolated to only certain locations in the operator's system. Trending is discussed further in the next section and can be applied when investigating issues such as described above.

Trend material failures

Trending material failures in a distribution system can provide useful information regarding whether or not a facility or group of facilities with common traits, needs to be replaced. Any and all aspects of the material failures experienced can be trended to gain information or find a pattern as to what happened, where it happened, if it will occur anywhere else, why it happened, and problematic areas to monitor for the same type of issue going forward. While there are many properties to trend, a few examples are: material manufacturer, material type, installation year, installation personnel, location or region, MAOP or operating stress, etc. When

trending, it is important to keep in mind that multiple types of material failures might be occurring. So, if no trends are found while comparing all locations where material failures occurred, then an operator should try categorizing the failures by another property or only comparing a certain subset of the locations where failures occurred to see if a trend becomes apparent. The operator can then utilize the results of the trending analysis to determine whether repair or replacement is the more appropriate response for each specific situation.

CRITERIA FOR MAKING REPAIR/REPLACE DECISIONS

Systematic approaches for making repair/replace decisions are presented below for four classes of pipelines.

1. Hazardous liquid pipelines
2. Natural gas transmission pipelines operated at stress levels of 30% of SMYS or more.
3. Natural gas transmission pipelines operated at stress levels less than 30% of SMYS
4. Natural gas distribution systems

Hazardous liquids are considered in one class regardless of operating stress level while natural gas transmission lines are divided into "high" stress and "low" stress classes. There are two reasons why gas pipelines but not liquid pipelines were segregated by the <30% stress level. The first has to do with how the gas and liquid regulations differ. Part 192, Subpart J separates pressure testing requirements for pipelines operated at stress levels below 30% of SMYS from those for pipelines operated at stress levels of 30% of SMYS or more. Also, miter bends are permitted in gas pipelines that are operated at stress levels below 30% of SMYS but not in pipelines operated at stress levels of 30% of SMYS or more. Part 195 recognizes "low stress" pipelines as those that are operated at stress levels of 20% of SMYS or less, but only those low stress pipelines with very low risk are exempt from pressure testing or any other requirements of Part 195.

The second reason why gas pipelines but not liquid pipelines were segregated by the <30% stress level has to do with fracture propagation risk, service interruption, and piggability. Gas pipelines are subject to long-running fractures when a failure occurs. This risk is considerably lower (but not negligible) for gas pipelines operated at stress levels below 30% of SMYS. The types of gas pipelines generally operated at less than 30% of SMYS are single-feed systems for a local gas distribution operator. Taking such a pipeline out of service for a pressure test is usually not possible. And, such pipelines generally are not piggable because of the low operating pressures and the flow rates of the gas. In contrast, while stress level does influence whether or not a liquid pipeline will leak or rupture when it fails, the length of any rupture that may occur (except for HVL pipelines) is generally insensitive to the operating stress level. Also, a low stress level in a liquid pipeline seems to present no barrier to pigging. Lastly, leaks and

spills from liquid lines can have severe impact on the environment regardless of the operating stress level of the pipeline.

The process for making repair/replace decisions in each case is based on a series of flow charts. It will be seen that these flowcharts constitute prescriptive procedures for making repair/replace decisions. These procedures are not meant to prevent a pipeline operator from conducting an engineering critical assessment of a pipeline that would allow the decision to be made outside of these prescriptive procedures.

Flowcharts for Transmission Pipelines

The flowcharts for making repair/replace decisions for transmission pipelines are presented in Appendix C, Figures C1 through C15. These figures cover all three types of transmission pipelines: hazardous liquid pipelines, natural gas transmission pipelines operated at stress levels of 30% of SMYS or more, and, natural gas transmission pipelines operated at stress levels less than 30% of SMYS.

Pipeline or System Attributes, Operational Data, and History

The pipeline attributes that are useful for making repair/replace decisions for hazardous liquid pipelines and natural gas transmission pipelines were presented previously in Tables 4 and 5 for the "base case" pipelines. The various operational data and historical operating experience that bear on repair/replace decision-making were discussed previously. The decision-making criteria are demonstrated below by means of examples. For each case discussed below complete sets of attributes, operational data, and historical operating experience are provided at the beginning of the discussion of each case. Note that no examples of pressure cycle data are provided because no actual fatigue analyses are carried out.

Base Case Example No. 1: Hazardous Liquid Pipeline Comprised of LF-ERW Pipe

Consider the 900-mile-long crude oil pipeline described in Table 4. It is comprised of 16-inch-OD, 0.250-inch-wall, X52 pipe manufactured with a LF-ERW seam and installed in 1953. Assume that the operator has records documenting all aspects of the pipeline's design, construction, and operation since 1953. The pipeline can accommodate all types of ILI tools. The failure history indicates one in-service rupture from external corrosion in 1984 and several in-service leaks and ruptures arising from manufacturing defects in the LF-ERW seam. The causes of the earlier seam failures are unknown because they were not thoroughly investigated. However, the later ones were found to have been caused by PCIF.

The operator has begun to employ periodic hydrostatic testing to assess the integrity of the pipeline from the standpoint of PCIF. The retest interval has been established via the type of

fatigue analysis explained earlier in the report. Records are available that show that early tests resulted in failures from external corrosion-caused metal loss. However, the more recent tests have produced test failures caused by seam manufacturing defects some of which had exhibited fatigue crack growth. Lastly, the operator has begun to utilize ILI periodically both to locate dents and to find and remediate external corrosion-caused metal loss. The re-inspection interval for corrosion assessment was established based on an assumed rate of corrosion, and the absence of corrosion-caused failures since the start of the assessments suggests that the process is working.

To determine whether or not this pipeline should be replaced, the operator can go through the process described below starting with Flowchart START (Figure C1 of Appendix C). Flowchart START as adapted to this particular pipeline is repeated as Figure 7 below.

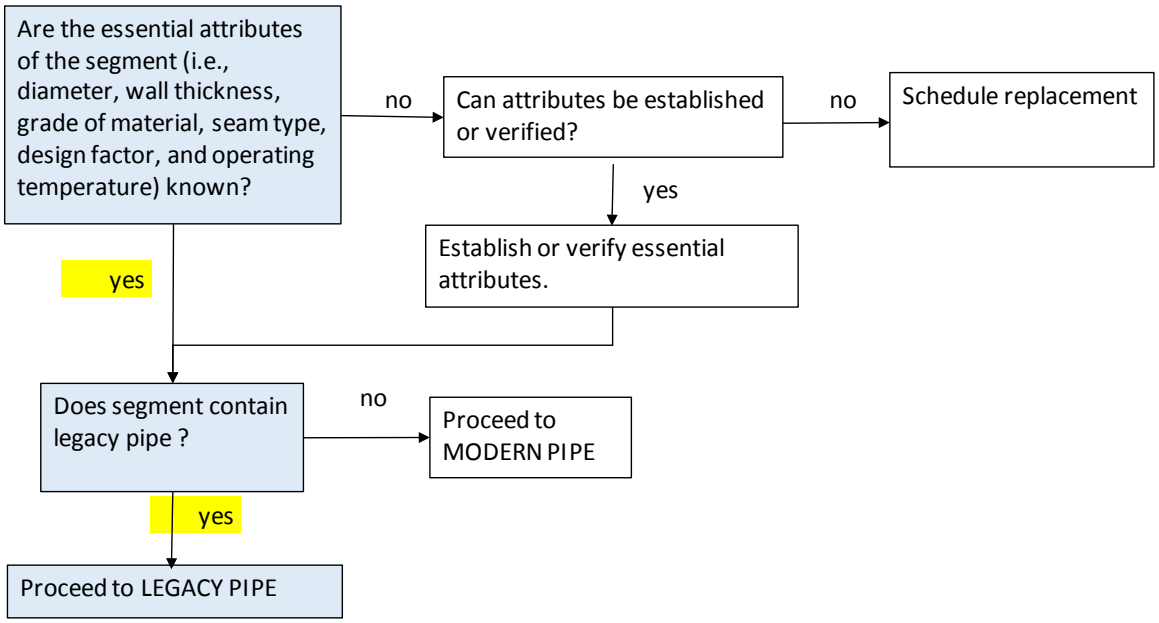


Figure 7. Start of Process to Decide Whether to Repair or Replace Base Case Hazardous Liquid Pipeline

The first question to answer in the process is: Are the essential design attributes of segment known? The answer based on the data in Table 4 is "yes". If the answer had been no, the operator would have to either establish or verify the essential design attributes or schedule replacement. The practical constraints on operating any pipeline safely mean that diameter, nominal wall thickness, grade of material (specified minimum yield strength or SMYS), type of longitudinal seam (to establish the "joint factor"), design factor (upper bound on operating hoop stress as a percent of SMYS) , and operating temperature are essential design attributes. These should be readily available from manufacturer's certificates, design calculations, and alignment sheets if such records have been retained in the operator's archives.

But, what if some or all of these essential attributes are not known? For a hazardous liquid pipeline, processes for establishing nominal wall thickness, grade of material, and joint factor when traceable, verifiable and complete records are not available are given in Part 195, §195.106. In the process of acquiring the samples to determining an unknown yield strength as required by §195.106, the operator should be able to establish the type of longitudinal seam. According to ASME B31.4, the standard design formula (the same as the one mandated by Part 195) is applicable as long as the operating temperature is between -20ºF and 250ºF. Diameter should be observable in above-ground portions of the pipeline, and it can be verified continually along the pipeline if the pipeline can accommodate running a caliper tool. Nominal wall thickness can be determined as specified in §195.106. Alternatively, wall thicknesses along the pipeline can be verified via in-line inspection with currently available ILI metal loss tools. Lastly, though it is not a part of federal regulations, it would seem that an operator could use the results of a recent hydrostatic test or could conduct a hydrostatic test to verify the integrity of the pipeline and establish its minimum pressure-carrying capacity. As in-line tools evolve, it may become possible to verify yield strengths and seam types along a pipeline as well as diameters and wall thicknesses.

The second question is: Does segment contain legacy pipe? The segment is comprised of LF-ERW pipe, so the answer is "yes". The operator must proceed to LEGACY PIPE. If the answer had been no, the operator would have been directed to the flowchart shown in Figure C8 in Appendix C (MODERN PIPE). The LEGACY PIPE flowchart as adapted to this particular pipeline is shown in Figure 8.

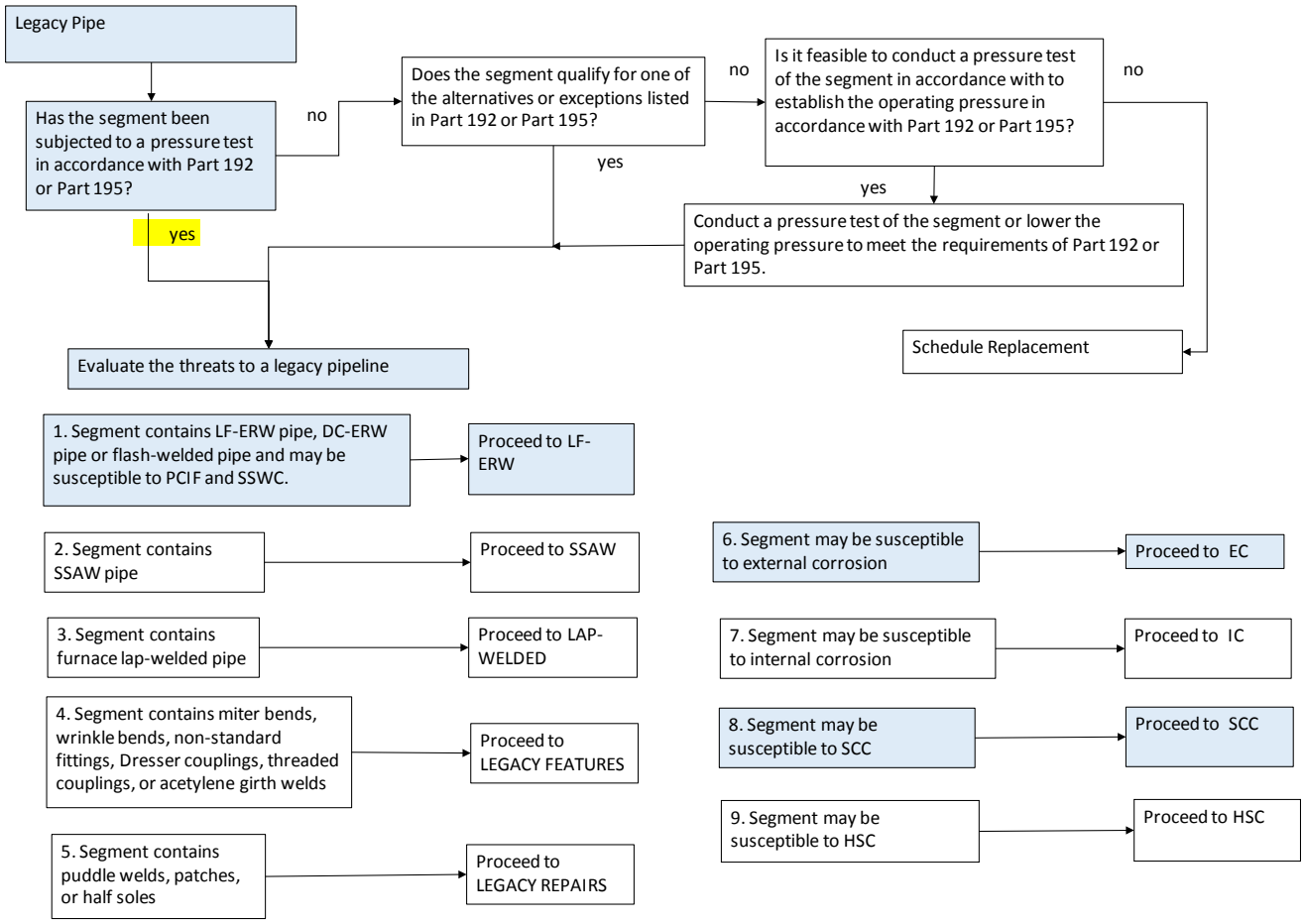


Figure 8. Threats to Address for Base Case Hazardous Liquid Pipeline Comprised of LF-ERW Pipe

According to Figure 8, the operator must review the pressure test history of the pipeline. If the pipeline has not been tested in accordance with the requirements of Part 195, and it does not qualify for one of the exceptions in the regulations, the operator must either conduct the appropriate test or lower the MOP to a level that would bring the pipeline into compliance with the regulations. If neither of these can be done, the operator should schedule replacement of the pipeline. This particular pipeline has been tested adequately.

This pipeline is comprised of LF-ERW pipe which can be susceptible to seam defects that may leak or become enlarged in service from PCIF and may also be susceptible to SSWC. In fact the history of the pipeline shows that it is susceptible to degradation from PCIF and external corrosion. Because of its operating stress level, it is potentially susceptible to SCC. Therefore, Cells 1, 7, and 9 are highlighted in Figure 8. The pipeline contains no SSAW pipe, no furnace lap-welded pipe, no miter bends, no wrinkle bends, no non-standard fittings, no Dresser couplings, no threaded couplings, no acetylene girth welds, no puddle welds, no patches, and no half-soles. Internal corrosion has never been detected via ILI or noticed at any time

segments of the pipe have been removed, and the pipeline carries crude oil with no sour components. ERW pipe is not prone to pipe body hard spots, and since this pipe was not manufactured by Youngstown Sheet and Tube Company it is not likely to have heat-affected-zone hardnesses of Rockwell C35 or more. Therefore, the threats represented by Cells 2-6 and 8 and 10 need not be considered. Based on the highlighted cells, the operator of this pipeline must pursue the process of making a repair/replace decision via Flowcharts LF-ERW, EC, and SCC (Figures C3, C12, and C14, respectively, of Appendix C). The first of these, Flowchart LF-ERW, as adapted to this particular pipeline is repeated as Figures 9A and 9B below.

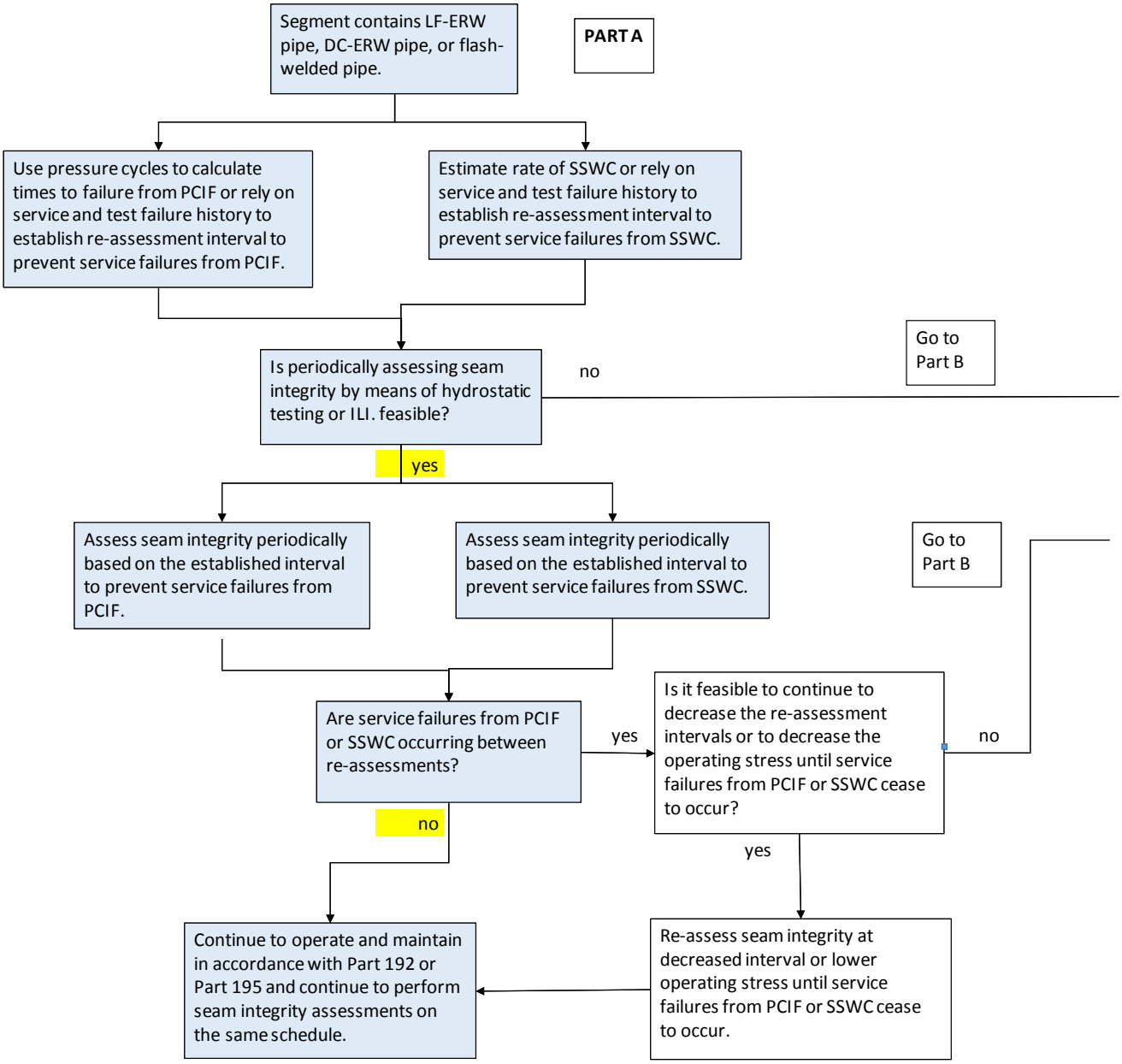


Figure 9A. Feasibility of Preventing in-Service Failures from PCIF or SSWC by Hydrostatic Testing or ILI

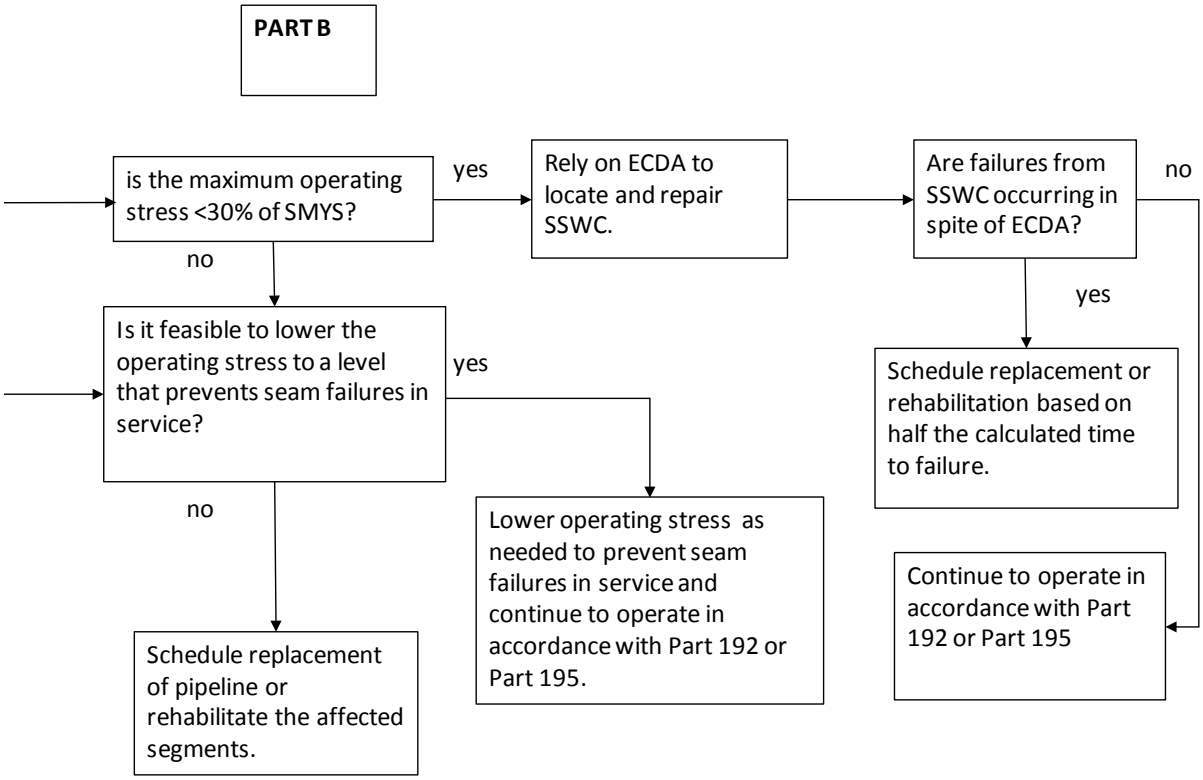


Figure 9B. Feasibility of Preventing in-Service Failures from PCIF or SSWC by Lowering Operating Pressure

Because the pipeline in question is comprised of LF-ERW pipe, the operator must assure its continued seam integrity by taking the necessary steps to prevent in-service leaks or ruptures from PCIF and selective seam weld corrosion (SSWC). As shown in Figure 9A, periodic seam integrity assessment via hydrostatic testing is being used to address PCIF, and it appears that the retest interval is sufficiently short to prevent in-service failures from PCIF. SSWC may be a threat for this pipeline even though no test failures have been caused by SSWC. The periodic testing to assess for PCIF also would be expected to reveal whether or not any serious SSWC has occurred. Therefore, the operator can continue to operate the pipeline employing the hydrostatic retesting on the same schedule.

Also as indicated in Figure 9A, the operator would have the option of employing ILI crack-detection technology in place of hydrostatic testing to address both PCIF and SSWC.

If the operator cannot or will not employ either hydrostatic testing or ILI to periodically re-assess the integrity of the ERW seam, lowering the operating pressure would be an option as shown in Figure 9B. However, it would be incumbent upon the operator to show that in-service failures from PCIF or SSWC would not be likely to occur at the lower MOP. If it is not possible

to have confidence that no such failures will occur, then replacement of the segment should be scheduled. Note that it may be possible to replace only those segments that are affected by a threat (or threats) that makes unacceptable the cost of continuing to repair. This could involve rehabilitation or pipe replacement at the problematic locations instead of replacement of the whole pipeline.

If in-service leaks or ruptures caused by either PCIF or SSWC continue to occur in spite of either a hydrostatic testing or ILI-based re-assessment program, the operator must either decrease the interval between assessments to the point where such failures cease to occur or schedule replacement of the pipeline or rehabilitation of the affected segments.

To keep the pipeline in service, the operator must satisfactorily address the threats of failure from external corrosion and stress corrosion cracking (SCC) to the point where no in-service failures are caused by either of these phenomena. Response to the threat of external corrosion as adapted to this particular pipeline are addressed via Flowchart EC repeated below as Figure 10.

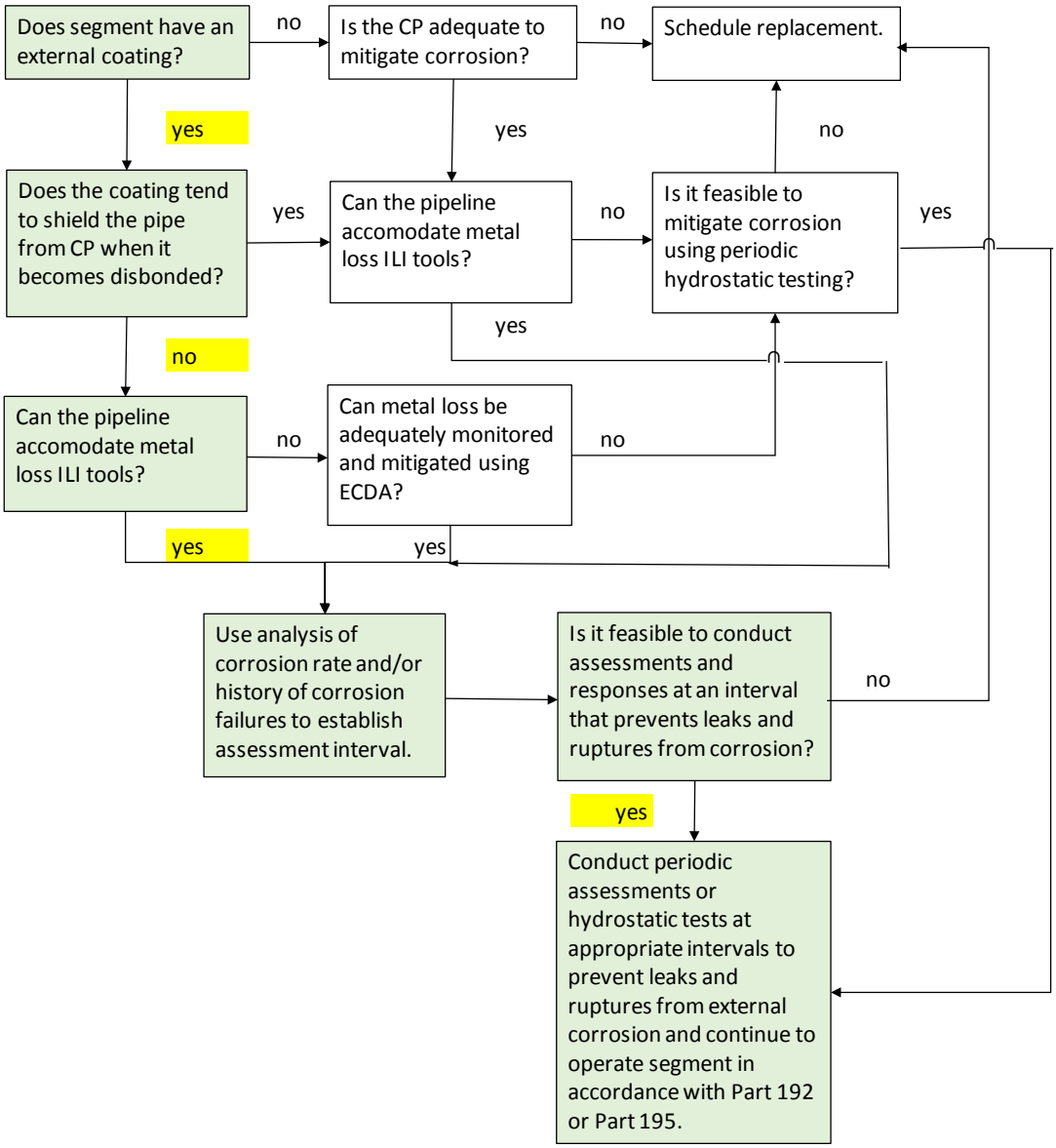


Figure 10. Feasibility of Preventing In-Service Failures from External Corrosion

Note that it is prudent to assume that any pipeline is susceptible to external corrosion, so the question "Is the segment susceptible?" is not asked. In the case of this particular hazardous liquid pipeline, the pipeline is coated and cathodically protected, but as its history shows, it has sustained a previous rupture from external corrosion. The coating on the pipeline is of a type that does not shield the pipe from cathodic protection if it disbonds. The pipeline can accommodate ILI metal loss inspection tools. Such tools are used to inspect the pipeline at intervals determined by analysis. Comparisons of successive inspections have shown the intervals to be sufficiently short to assure the absence of in-service failures from external corrosion. Therefore, replacement of the pipeline from the standpoint of the threat of external corrosion does not have to be considered. Note that unburying the pipeline, lifting it out of the

ditch, blasting off the old coating, repairing or removing corroded pipe, re-coating the pipeline, and lowering and re-burying it could be done in place of total replacement.

If the pipeline cannot accommodate ILI metal-loss inspection tools, the operator could consider addressing the corrosion threat by utilizing external corrosion direct assessment (ECDA). This is possible because the coating on this pipeline does not shield the pipe from cathodic protection if it becomes disbonded. As long as the ECDA program is successful in preventing in-service failures from external corrosion, replacement from the standpoint of the threat of external corrosion does not have to be considered.

If it is not feasible for the operator to use either ILI or ECDA, periodic hydrostatic testing could be used to control the threat of external corrosion. However, this is generally an inefficient means of assessing integrity from the standpoint of corrosion because of the inability of testing to reveal short, deep defects. If hydrostatic testing is chosen as the means of assessment for external corrosion, a close-interval pipe-to-soil potential survey done in conjunction with the test may greatly improve the likelihood of finding the short, deep defects that survive the test. Moreover, in cases where ECDA can be used effectively, ECDA combined with a hydrostatic test would improve the likelihood of finding severe corrosion regardless of its configuration

The threat of SCC as adapted to this particular pipeline is addressed via Flowchart SCC repeated below as Figure 11.

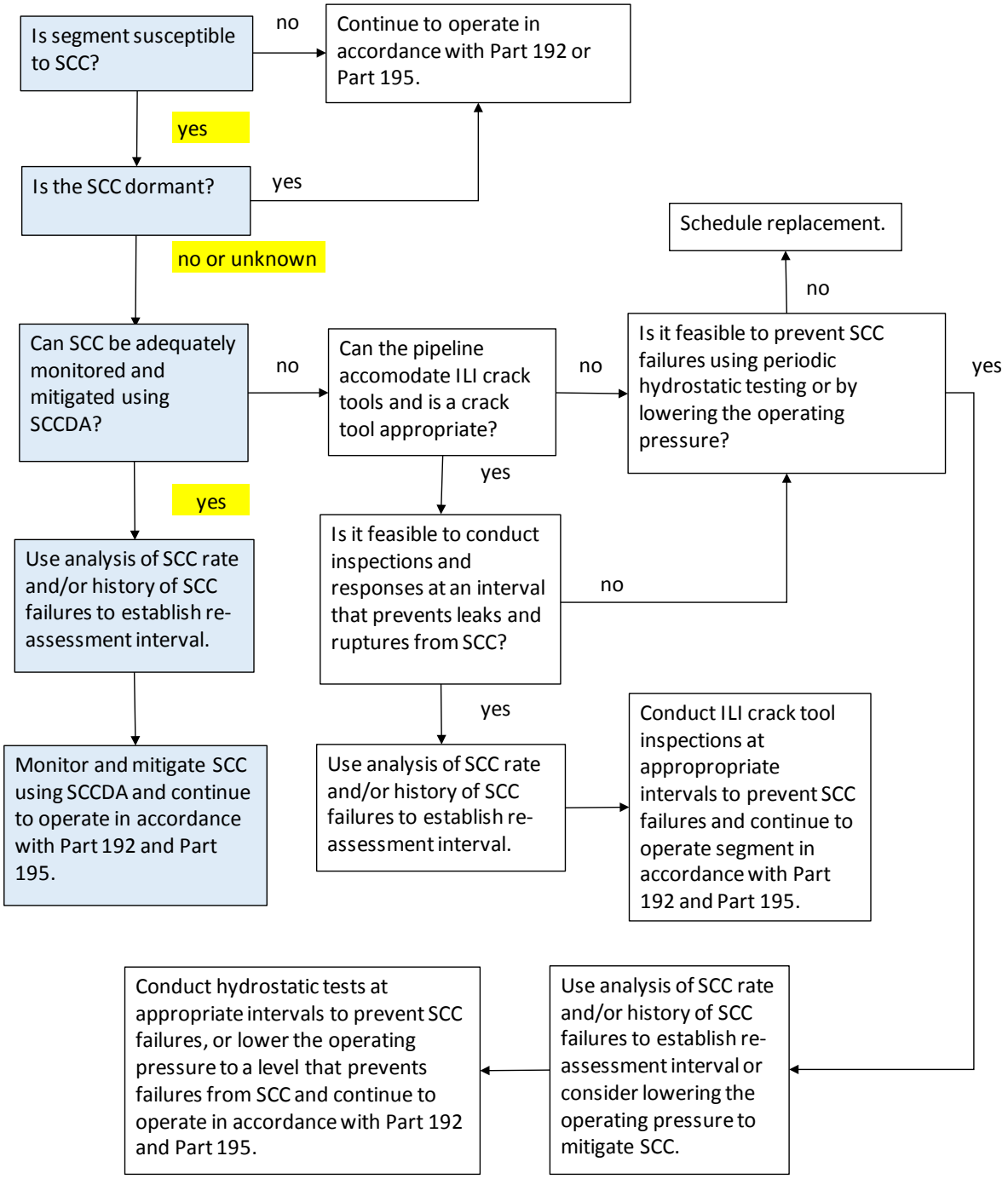


Figure 11. Feasibility of Preventing In-Service Failures from SCC

Not every pipeline is susceptible to SCC, so the process begins with the question "Is the segment susceptible to SCC?"[26]. In the case of this particular pipeline the question cannot be answered "no" because the operator does not know whether it is or not. The pipeline is operated at a high enough stress level for SCC to be possible, and the coating is not fusion bonded epoxy (which usually mitigates the SCC-forming environment). The answer to the second question "Is the SCC dormant?" is "unknown". In response to a potential SCC threat, the operator has three choices:

1. Use SCCDA periodically to locate areas where SCC may be occurring.
2. Periodically conduct ILI with an appropriate crack-detection tool and repair cracks.
3. Periodically conduct hydrostatic tests.

The flowchart in Figure 11 runs through these choices in order, but the operator should make the choice appropriate to the circumstances of the particular pipeline. For a pipeline where SCC is known to exist because of past SCC failures, either ILI or hydrostatic testing would seem to be the preferred options. On the other hand, if no evidence of SCC has surfaced, it could make sense for the operator to choose SCCDA.

The operator of the Base Case Example No. 1 pipeline has seen no evidence that SCC is present but prudently decides to use SCCDA to err on the safe side. At least, the operator will likely get an early warning if SCC should develop. Besides, the hydrostatic testing that is necessary to address the PCIF threat will likely expose any potential SCC threat in the form of a test failure before the cracks could become large enough to fail in service. Alternatively, the operator may be able to show by analysis using the Fessler-Rapp method[xxiii] that the testing for PCIF adequately assesses the integrity of the pipeline from the standpoint of SCC as well. In that case SCCDA would not be needed.

If the pipeline were known to be affected by SCC, and SCCDA proved to be an unreliable way to find and mitigate the phenomenon, the operator would have to rely on ILI crack detection technology or periodic hydrostatic testing to mitigate the problem. Alternatively, it may be possible to mitigate the SCC threat by lowering the operating pressure. If the operator were able to control the problem (i.e., prevent leaks and ruptures from SCC), then the pipeline would not need to be replaced.

[26] One can refer to ASME B31.8S or API RP 1160 to access guidance on determining susceptibility of SCC or to Integrity Management of Stress Corrosion Cracking in Gas Pipeline High Consequence Areas STP-PT-011 – 2008 to access guidance on integrity management of SCC in general.

The above analysis indicates that the threats to the integrity of this pipeline are being mitigated by the on-going maintenance and integrity assessment actions being taken by the operator. The question of whether or not the operator should continue to operate this pipeline versus replacing it can be made on the basis of the cost to maintain and re-assess its integrity and safety versus the cost to replace it. If these continuing costs are acceptable to the operator, then replacement is not necessary.

Base Case Example No. 2: A Natural Gas Pipeline Comprised of Flash-Welded Pipe Operated at a Stress Level of 72% of SMYS

Consider the natural gas transmission pipeline described in Table 5. It is comprised of 30-inch-OD, 0.375-inch-wall, X52 pipe manufactured with a flash-welded seam and installed in 1960. The pipeline was subjected to a pre-service hydrostatic test to a minimum stress level of 90% of SMYS. It is operated at a maximum hoop stress level of 72% of SMYS in Class 1 locations. The operator has records documenting all aspects of the pipeline's design, construction, and operation since 1960, and the pipeline can accommodate all types of ILI tools. The failure history indicates two in-service ruptures from external corrosion, one in 1971 and one in 1984. In addition, an in-service rupture caused by selective seam weld corrosion (SSWC) occurred in 1995, and an in-service rupture arising from high-pH stress corrosion cracking (SCC) occurred in 1999.

The operator decided to employ periodic hydrostatic testing of the first two valve sections downstream of the compressor stations to assess integrity from the standpoint of SCC after the occurrence of an SCC in-service rupture in 1999. The first tests for that purpose were conducted in 1999 to a maximum hoop stress level of 110% of SMYS. The operator assumed that the rate of SCC growth could be as high as 0.024 inch per year, the rate suggested in Reference XXIV. The failure-pressure-defect-size relationship shown in Figure 12 was used to determine an appropriate interval of time before a second test should be conducted.

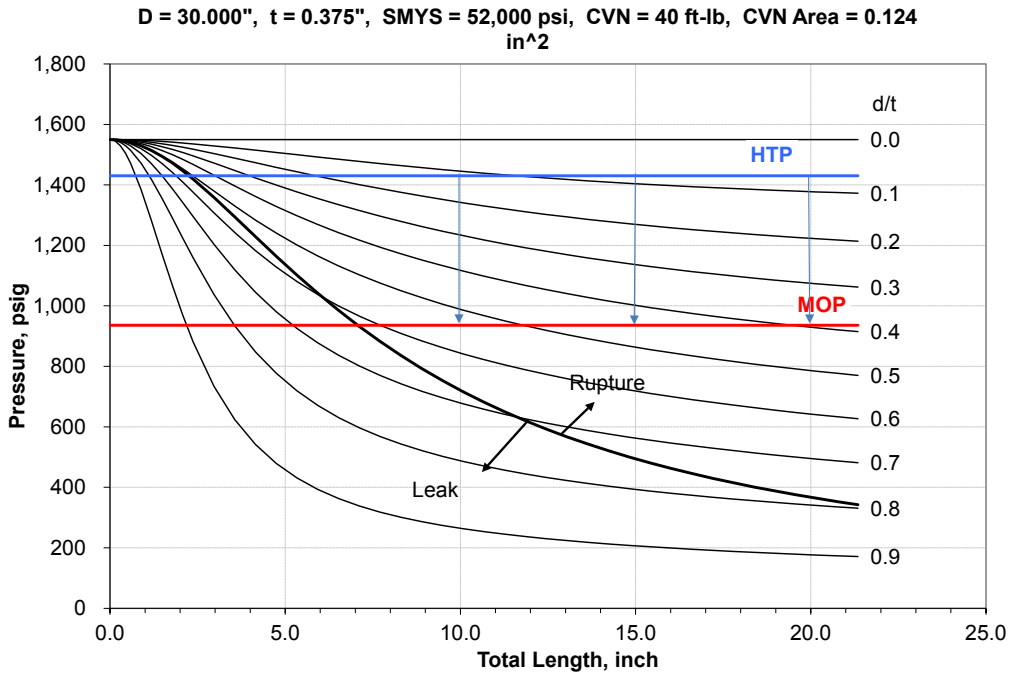


Figure 12. Time to Failure at the MOP after a Test (HTP) to 110% of SMYS

The 20-inch-long defect in Figure 12 appears to have the shortest time to failure for long defects. It would be expected to survive the test to 110% of SMYS if its depth did not exceed 8% of the wall thickness, and it would be expected to fail at the MAOP of 72% of SMYS if its depth reached 40% of the wall thickness. The corresponding amount of defect growth is 0.32 times the wall thickness of 0.375 inch or 0.120 inch. At a growth rate of 0.024 inch per year, the expected time to failure would be 5 years. The operator elects to conduct another hydrostatic test of the same segments to the same test stress levels 2 years after the first test (a factor of safety of 2.5).

In 2006 the publication of the Fessler/Rapp method for scheduling hydrostatic tests to mitigate SCC was developed. The operator decides to base the timing of future hydrostatic tests on the Fessler/Rapp method. Since the method is strongly influenced by the flow stress of the material with higher flow stress levels giving more conservative results, the operator uses lists of yield and ultimate tensile test results from the manufacturer of the order to calculate the upper-95-percentile yield and tensile strengths, 60,000 psi and 85,000 psi, respectively. The flow stress is the average of these two, or 72,500 psi. The resulting times for future retests are based on Figure 13.

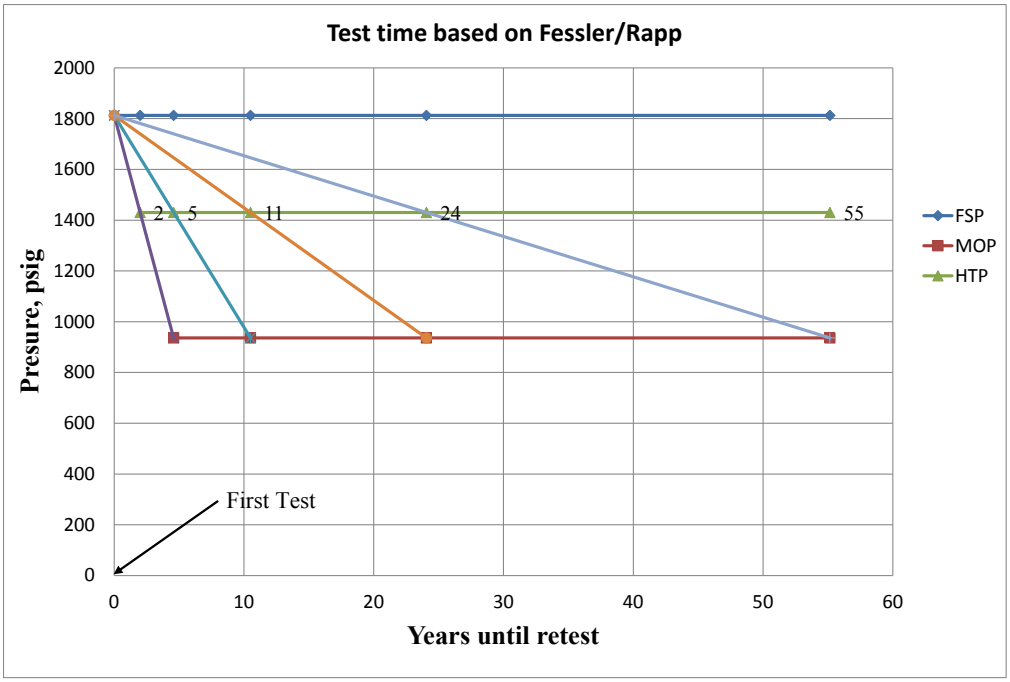


Figure 13. Times for Retests to Control SCC based on the Fessler/Rapp Method

On the basis of the Fessler/Rapp method, the retests should occur at 2, 5, 11, 24, and 55 years after the first test. Note that the first test was conducted in 1999 arbitrarily followed by a second test in 2001. A third test was conducted in 2004. These tests though scheduled at arbitrary intervals, coincidentally, would have been the ones predicted by the Fessler/Rapp method, had it existed in 1999. Three test breaks from SCC occurred during the 1999 test, one at a test stress level of 78% of SMYS. Two test breaks from SCC occurred during the 2001 test. The lowest failure stress level for an SCC break was 99% of SMYS. In the 2004 test only one test break from SCC occurred at a stress level of 101% of SMYS. The decreasing numbers of test breaks and increasing levels of failure stress suggested that the SCC threat was being adequately addressed by the successive hydrostatic tests. On the basis of the Fessler/Rapp calculations another hydrostatic test was to have taken place in 2010. Instead, the operator elected to run an EMAT ILI tool to assess the entire pipeline for SCC.

Hydrostatic test failures from causes other than SCC occurred during the 1999, 2001, and 2004 hydrostatic tests. Two test breaks during the 1999 test were caused by SSWC and 9 test breaks were caused by seam splits. The lowest failure stress level associated with an SSWC rupture was 81% of SMYS. Nine seam splits from manufacturing defects (confirmed to be hook cracks with no evidence of in-service crack growth) occurred during the 1999 test. The splits occurred at stress levels above the highest previous levels to which the pipe had subjected in the pre-service hydrostatic test. One SSWC break occurred in the 2001 test at a stress level of 98% of SMYS. No SSWC break occurred in the 2004 test. Seam splits occurred in both the 2001 test and the 2004 test, but they were fewer in number than in the 1999 test and occurred

at higher stress levels. The results of the three successive hydrostatic tests in 1999, 2001, and 2004 suggest that the threats of SSWC and seam manufacturing defects are being adequately addressed by hydrostatic testing.

The operator of the pipeline has utilized ILI in various situations. Following the in-service external corrosion rupture in 1985, a low-resolution MFL tool was run through the entire pipeline to locate and investigate other possible metal loss areas. Two hundred locations of metal loss were identified and prioritized by severity. Fifty of these were excavated and examined. Fifteen of the areas of metal loss were found to warrant repairs in the form of full-encirclement sleeves. The rectifier outputs were enhanced such that pipe-to-soil potential readings at all test leads were brought up to -850 milivolts ($Cu,CuSO_4$).

Following the occurrence of an in-service failure from SSWC in 1995, the operator used a high-resolution MFL tool to locate and investigate metal loss. The tool was not specifically designed to find narrow slot-like defects such as SSWC, but the operator hoped that SSWC would be located in conjunction with the examinations of other metal loss anomalies. Seven hundred and twenty metal loss anomalies were graded and prioritized by the vendor. Fifty of those were examined via excavations. Two were found to contain SSWC, but the dimensions of the SSWC had not been accurately defined by the MFL technology. After hydrostatic testing began in 1999 to address the SCC threat, it was assumed that any SSWC that was severe would fail in the hydrostatic tests.

In 2004 the operator began an integrity management program in which a high-resolution metal loss inspection and a caliper-type dent inspection of the entire pipeline were to be conducted every 7 years. The two inspections were repeated in 2011, and the next round of such inspections is scheduled for 2018.

In 2010, the operator elected to address the SCC threat for the entire pipeline with EMAT ILI technology instead of continuing to test certain valve sections based on the Fessler/Rapp calculations. The results were satisfactory in terms of locating and characterizing SCC, so it is likely that the operator will continue to use the technology on a periodic basis to assess the integrity of the pipeline from the standpoint of SCC. The time for the next assessment was established based on the apparent crack growth since the last hydrostatic test in 2004.

Because, hydrostatic testing as a means of verifying integrity was discontinued in 2010, the operator began to utilize CMFL technology in 2014 to assess the integrity of the entire pipeline from the standpoint of SSWC. The results were sufficiently satisfactory that the operator plans to conduct such inspections periodically. The time for the next assessment was established based on the apparent SSWC growth since the last hydrostatic test in 2004.

Another consequence of discontinuing hydrostatic testing is that seam integrity must now be verified by other means. The threat of failure from seam manufacturing anomalies growing by PCIF would seem to be quite low. This is because, although seam defects have ruptured during previous hydrostatic tests, none has exhibited any evidence of in-service crack growth (based on detailed examinations of the fracture surfaces of seam anomalies that failed in the tests), and all of the test failures caused by seam anomalies have occurred at pressure levels above that of the manufacturer's hydrostatic test (to 90% of SMYS). The operator should perform a pressure-cycle-fatigue analysis via the technique suggested previously. In all likelihood, such and analysis would show that a defect that could have survived the highest previous hydrostatic test stress (minimum of 100% of SMYS) would not be expected to fail for hundreds of years. Such an outcome would be expected because the ratio of test pressure to operating pressure and the level of operating stress assure that no large seam defect could exist. Nevertheless, the operator should alert the ILI service vendor that inspections for cracks should include looking for seam anomalies as well as SCC and SSWC.

Note that a threat to seam integrity from PCIF in a natural gas transmission pipeline can be significant if the pipeline was not given a pre-service hydrostatic test, if the pre-service hydrostatic test was to a level of only 1.1 times the MAOP, or if the pipeline is operated at a maximum stress level that is much less than 72% of SMYS (i.e., 30 to 50 percent of SMYS) and has only been tested to a level of 1.25 times the MAOP.

To determine whether or not this pipeline should be replaced, the operator can go through the process described below starting with START (Figure C1 of Appendix C). Flowchart START as adapted to this particular pipeline is repeated as Figure 14 below.

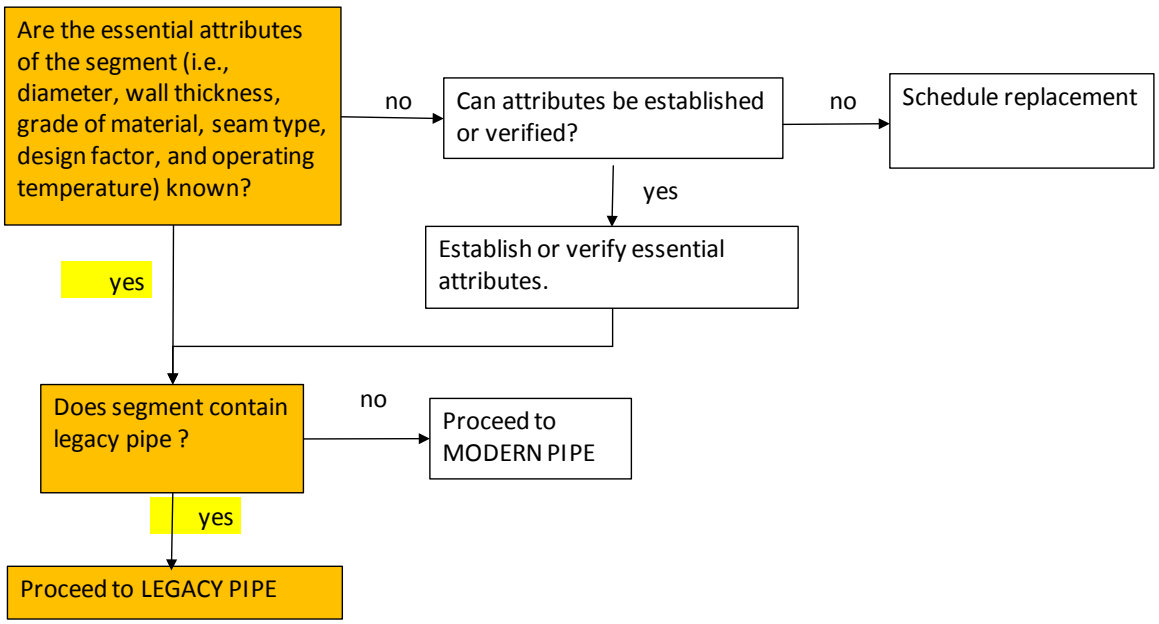


Figure 14. Start of Process to Decide Whether to Repair or Replace the Base Case Natural Gas Pipeline that is Operated at a Stress Level of 72% of SMYS

The first question to answer in the process is: Are the essential design attributes of segment known? The answer based on the data in Table 5 is "yes". If the answer had been no, the operator would have to either establish or verify the essential design attributes or schedule replacement. The practical constraints on operating any pipeline safely mean that diameter, nominal wall thickness, grade of material (specified minimum yield strength or SMYS), type of longitudinal seam (to establish the "joint factor"), design factor (upper bound on operating hoop stress as a percent of SMYS) , and operating temperature are essential design attributes. These should be readily available from manufacturer's certificates, design calculations, and alignment sheets if such records have been retained in the operator's archives.

But, what if some or all of these essential attributes are not known? For a natural gas pipeline, processes for establishing nominal wall thickness, grade of material, and joint factor when traceable, verifiable and complete records are not available are given in Part 192, §192.105. In the process of acquiring the samples required by §192.107 to determine an unknown yield strength, the operator should be able to establish the type of longitudinal seam. Diameter should be observable in above-ground portions of the pipeline, and it can be verified continually along the pipeline if the pipeline can accommodate running a caliper tool. Nominal wall thickness can be established as described in §192.109. Alternatively, wall thicknesses along the pipeline can be verified via in-line inspection with currently available ILI metal loss tools. The design factor can be determined as specified in §192.111, and the joint factor can be established from the identified type of seam as specified in §192.113. There will be no need for temperature derating as long as the operating temperature does not exceed 250ºF. Lastly,

though it is not a part of federal regulations, it would seem that an operator could use the results of a recent hydrostatic test or could conduct a hydrostatic test to verify the integrity of the pipeline and establish its minimum pressure-carrying capacity. As in-line tools evolve, it may become possible to verify yield strengths and seam types along a pipeline as well as diameters and wall thicknesses.

The second question is: Does segment contain legacy pipe? The segment is comprised of flash-welded pipe, so the answer is "yes". The operator must proceed to LEGACY PIPE. If the answer had been no, the operator would have been directed to the flowchart shown in Figure C8 in Appendix C (MODERN PIPE). The LEGACY PIPE flowchart as adapted to this particular pipeline is shown in Figure 15.

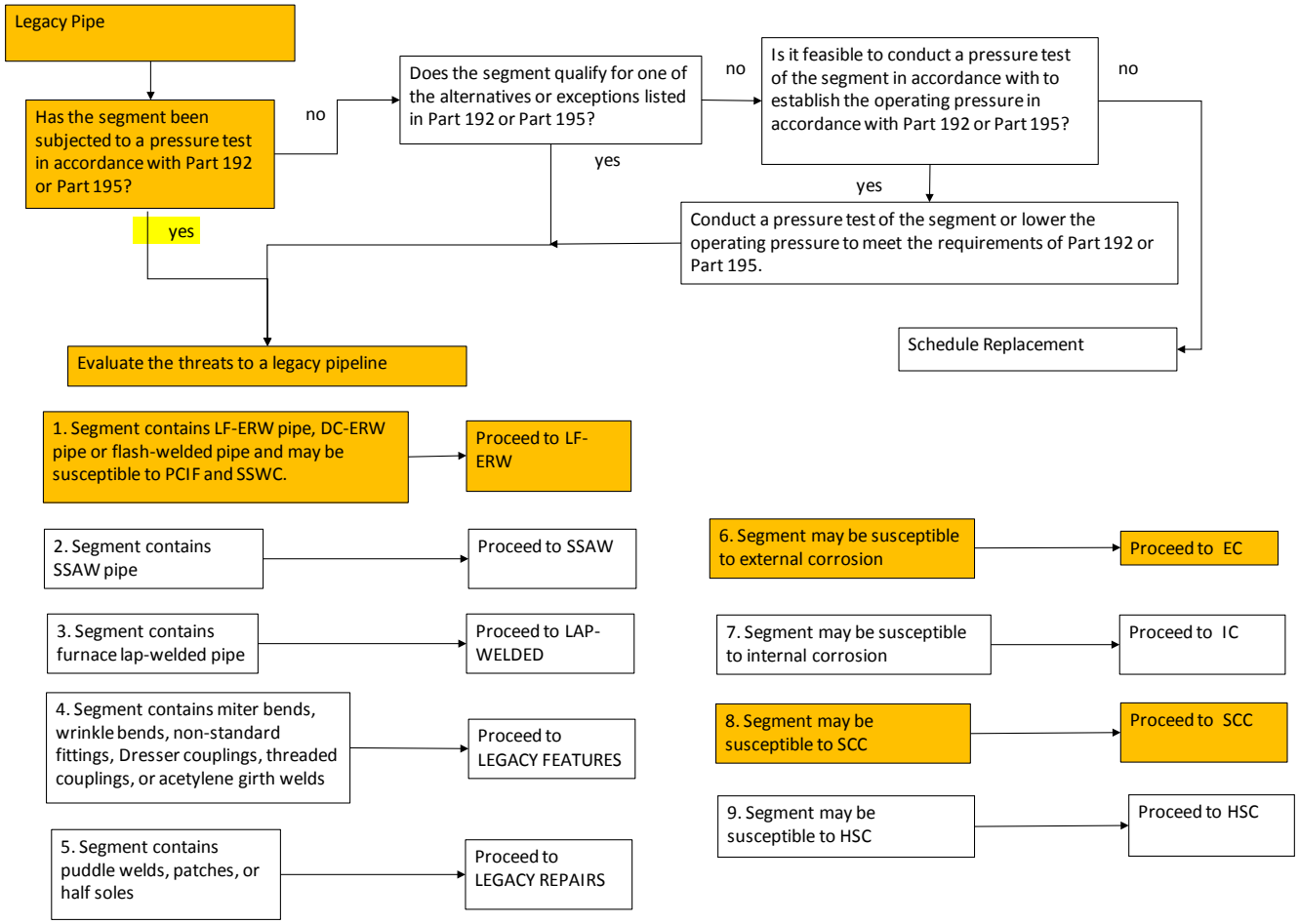


Figure 15. Threats to Address for Base Case Natural Gas Pipeline Comprised of Flash-welded Pipe that is Operated at a Stress Level > 30% of SMYS

As shown in Figure 15, the operator must review the pressure test history of the pipeline. If the pipeline has not been tested in accordance with the requirements of Part 192, and it does

not qualify for one of the exceptions in the regulations, the operator must either conduct the appropriate test or lower the MAOP to a level that would bring the pipeline into compliance with the regulations. If neither of these can be done, the operator should schedule replacement of the pipeline. This particular pipeline has been tested adequately.

This pipeline is comprised of flash-welded pipe which can be susceptible to the seam defects that may leak or become enlarged in service from PCIF and may also be susceptible to SSWC. In fact, the history of the pipeline shows that it is susceptible to degradation from SSWC, external corrosion, and SCC. Therefore, Cells 1, 7, and 9 are highlighted in Figure 15. The pipeline contains no SSAW pipe, no furnace lap-welded pipe, no miter bends, no wrinkle bends, no non-standard fittings, no Dresser couplings, no threaded couplings, no acetylene girth welds, no puddle welds, no patches, and no half-soles. Internal corrosion has never been detected via ILI or noticed at any time segments of the pipe have been removed, and the pipeline carries dry natural gas with no sour components. Neither pipe body hard spots nor hard heat-affected-zones adjacent to the seam exist. Therefore, the threats represented by Cells 2-6 and 8 and 10 need not be considered.

Based on the highlighted cells, the operator of this pipeline must pursue the process of making a repair/replace decision via Flowcharts LF-ERW, EC, and SCC. The first of these, Flowchart LF-ERW (Figure C3 of Appendix C) as adapted to this particular pipeline is repeated as Figures 16A and 16B below.

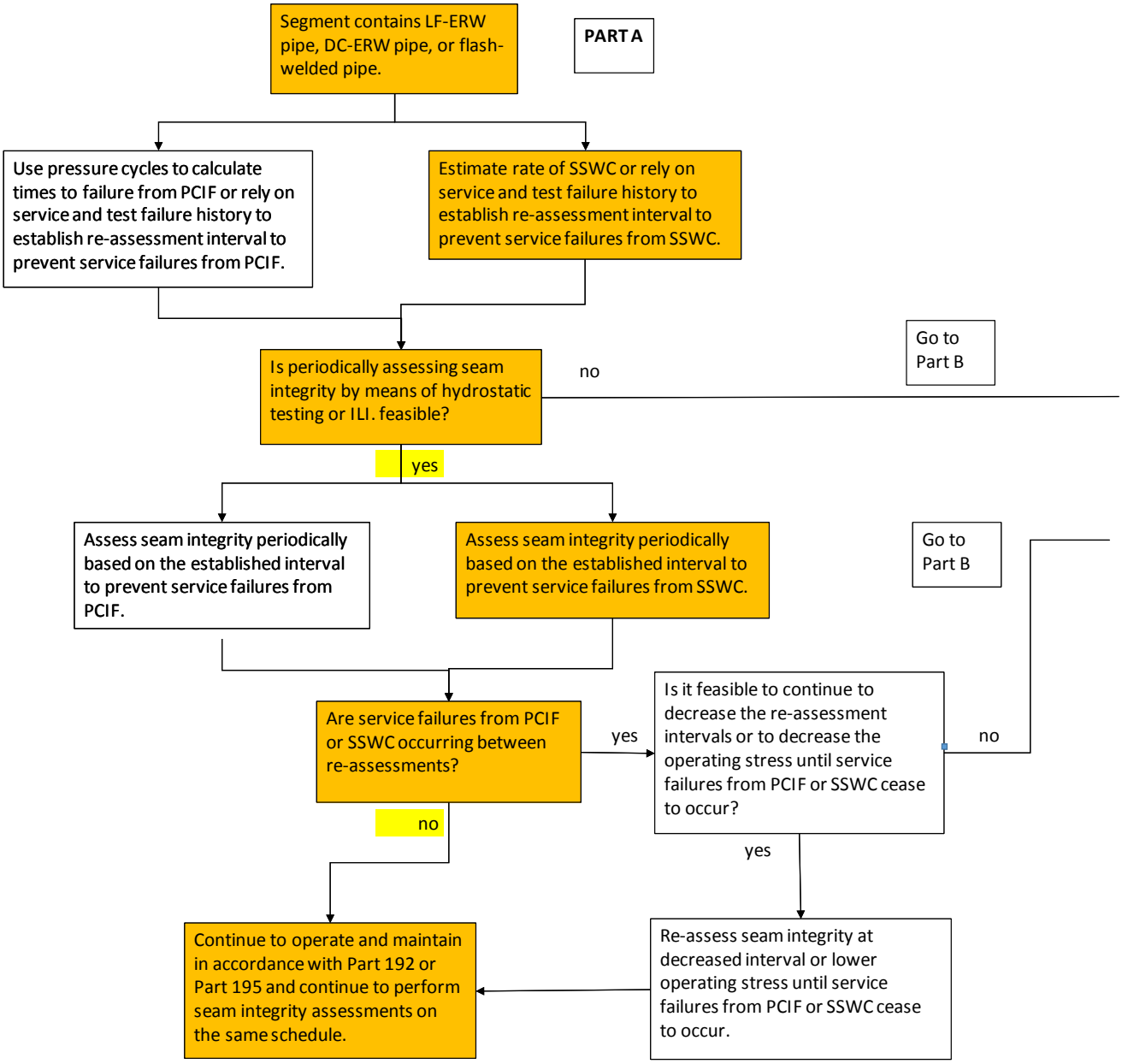


Figure 16A. Feasibility of Preventing in-Service Failures from PCIF or SSWC by Hydrostatic Testing or ILI

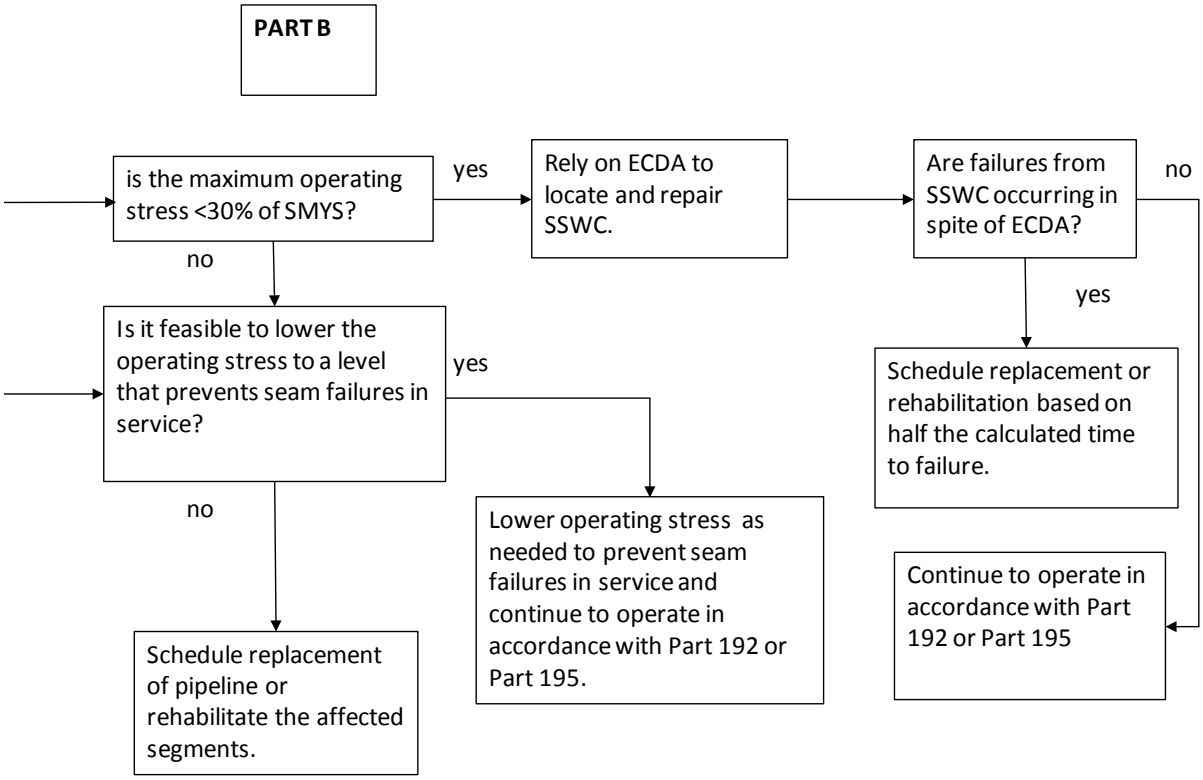


Figure 16B. Feasibility of Preventing in-Service Failures from PCIF or SSWC by Lowering Operating Pressure

The operator examines the fatigue effect of the pressure spectrum and determines that it is unlikely that PCIF will be an integrity threat within the useful life of the pipeline. The periodic retesting for SCC provides additional assurance that it is not, because no test failures have been caused by PCIF. However, because the pipeline is comprised of flash-welded pipe, the operator must assure its continuing seam integrity by taking the necessary steps to prevent in-service leaks or ruptures from selective seam weld corrosion (SSWC) as shown in Figure 16A. Periodic seam integrity assessment via hydrostatic testing was being used to address SCC, but the retest interval, if based on a Fessler-Rapp analysis, could be short enough to prevent in-service failures from SSWC as well. Therefore, the operator would need to continue to employ the hydrostatic retesting on the same schedule. In 2010, to avoid the disruptive effect of continued hydrostatic testing, the operator chose the option of employing ILI crack-detection technology to address SCC and CMFL technology to address SSWC.

In place of hydrostatic testing and ILI, as indicated in Figure 16B, the operator could also choose to lower the operating pressure of the pipeline to lessen the likelihood of failure from all causes. However, it would be incumbent upon the operator to show that in-service failures from SCC or SSWC would not be likely to occur at the lower MAOP.

If in-service leaks or ruptures caused by SCC or SSWC continue to occur in spite of either a hydrostatic testing or ILI-based re-assessment program, the operator must either decrease the interval between assessments to the point where such failures cease to occur or schedule replacement of the pipeline.

As noted in conjunction with the Base Case No. 1 example, total replacement may not be necessary. In many cases, it might be possible to identify and rehabilitate only those segments that are affected by a particular threat (or threats) that are judged to be too costly to address by continued assessment and repair. Such rehabilitation could involve recoating of the pipe and/or replacement of some pipe, not necessarily the whole pipeline.

To keep the pipeline in service, the operator must satisfactorily address the threats of failure from external corrosion, SSWC, and SCC to the point where no in-service failure is caused by any of these phenomena. The threat of external corrosion as adapted to this particular pipeline is addressed via Flowchart EC (Figure C12 of Appendix C) repeated below as Figure 17.

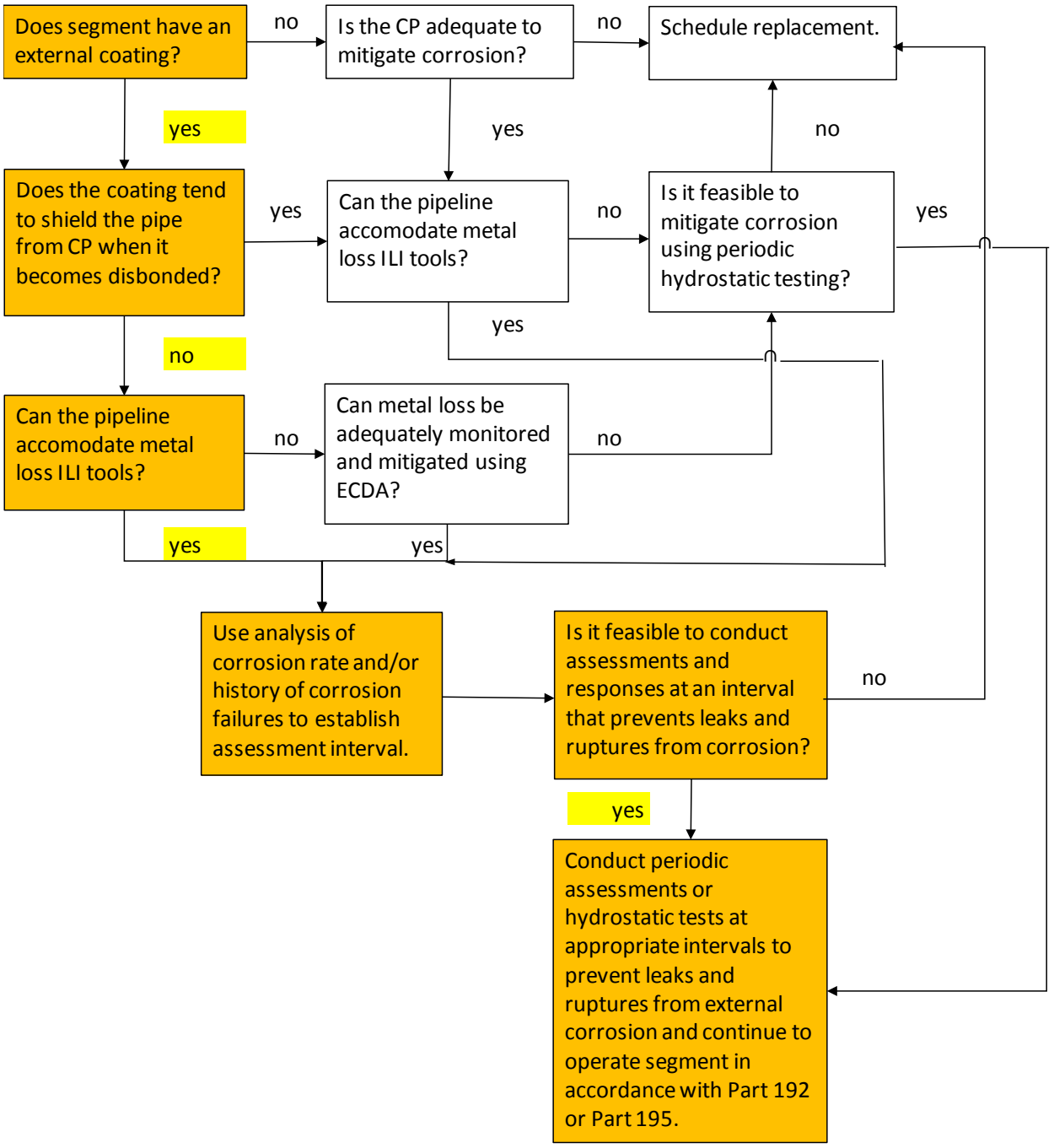


Figure 17. Feasibility of Preventing In-Service Failures from External Corrosion

This particular natural gas pipeline is coated and cathodically protected, but as its history shows, it has sustained previous ruptures from external corrosion. The coating on the pipeline is of a type that does not shield the pipe from cathodic protection if it disbonds. The pipeline can accommodate ILI metal loss inspection tools, and such tools are used to inspect the pipeline at intervals determined by analysis. Comparisons of successive inspections have shown the intervals to be sufficiently short to assure the absence of in-service failures from external

corrosion. Therefore, replacement of the pipeline from the standpoint of the threat of external corrosion does not have to be considered.

If the pipeline could not accommodate ILI metal-loss inspection tools, the operator could consider addressing the corrosion threat by utilizing external corrosion direct assessment (ECDA). This is possible because the coating on this pipeline does not shield the pipe from cathodic protection if it becomes disbonded. As long as the ECDA program is successful in preventing in-service failures from external corrosion, replacement from the standpoint of the threat of external corrosion does not have to be considered.

If it is not feasible for the operator to use either ILI or ECDA, periodic hydrostatic testing could be used to control the threat of external corrosion. However, this is generally an inefficient means of assessing integrity from the standpoint of corrosion because of the inability of testing to reveal short, deep defects. If hydrostatic testing is chosen as the means of assessment for external corrosion, a close-interval pipe-to-soil potential survey done in conjunction with the test may greatly improve the likelihood of finding the short, deep defects that survive the test.

The threat of SCC as adapted to this particular pipeline is addressed via Flowchart SCC (Figure C14 of Appendix C) repeated below as Figure 18.

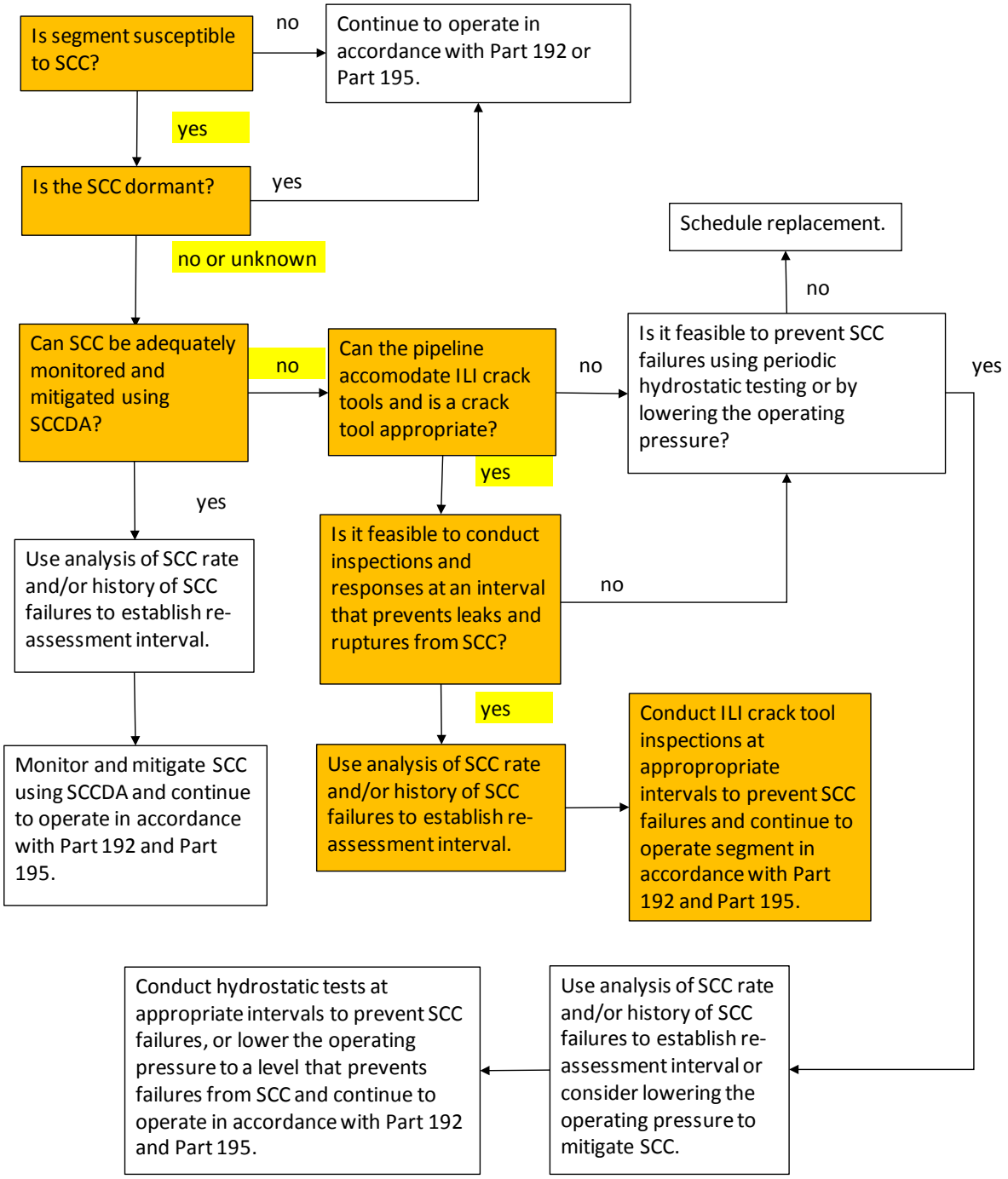


Figure 18. Feasibility of Preventing In-Service Failures from SCC

Because of the occurrence of one in-service failure from SCC, this pipeline is clearly susceptible to SCC. The operator has no reason to believe the SCC is dormant, so the answer to the second question "Is the SCC dormant?" is "unknown". As was noted in conjunction with the Base Case No. 1 pipeline, the operator has three choices:

1. Use SCCDA periodically to locate areas where SCC may be occurring.
2. Periodically conduct ILI with an appropriate crack-detection tool and repair cracks.
3. Periodically conduct hydrostatic tests.

The flowchart in Figure 18 runs through these choices in order, but the operator should make the choice appropriate to the circumstances of the particular pipeline. For a pipeline where SCC is known to exist because of past SCC failures, either ILI or hydrostatic testing would seem to be the preferred options.

The operator suspects that SCC is present in other locations downstream from compressor stations and decides that using SCCDA is not a sufficiently robust response to the threat. Hydrostatic testing was chosen to assess the integrity of the first two valve sections downstream from each compressor station. Initially, an arbitrary retest frequency of every two years was chosen. After 2006 when the Fessler/Rapp method was published, the test intervals were to be chosen via the Fessler/Rapp analysis. By 2010, however, the operator became convinced that EMAT ILI technology would be capable of addressing the threat of SCC, and hydrostatic testing was abandoned in favor of using ILI. Another type of ILI, the CMFL tool, is chosen to assess the pipeline for SSWC in place of hydrostatic testing. The operator plans to periodically conduct pressure-cycle analyses to assure that PCIF remains a non-threat.

The above analysis indicates that the threats to the integrity of this pipeline are being mitigated by the on-going maintenance and integrity assessment actions being taken by the operator. The question of whether or not the operator should continue to operate this pipeline versus replacing it can be made on the basis of the cost to maintain and re-assess its integrity and safety versus the cost to replace it. If these continuing costs are acceptable to the operator, then replacement is not necessary.

Base Case Example No. 3: A Natural Gas Pipeline Operated at Stress Levels Less than 30% of SMYS

Consider the following natural gas transmission pipeline. It is comprised of 24-inch-OD, 0.281-inch-wall, X42 pipe manufactured with a flash-welded seam and installed in 1949. Each piece of pipe was hydrostatically tested by the manufacturer to a stress level of 90% of SMYS for a total time of 10 seconds. The pipeline is operated at a maximum hoop stress level of nearly 30% of SMYS. The MAOP of the pipeline is 290 psig (29.5% of SMYS). The operator has records documenting all aspects of the pipeline's design, construction, and operation since 1949. The pipeline cannot accommodate ILI tools. The pipeline has no facilities for launching or receiving pigs, the mainline valves are not full-opening valves, and the pressure and flow rate are inadequate for pushing a pig. The pipeline also contains 50 miter bends that may pose obstructions for ILI tools. The failure history indicates three in-service leaks from external

corrosion, one in 1959, one in 1964, and one in 1984. In addition, an in-service rupture caused by selective seam weld corrosion (SSWC) occurred in 1995.

The pipeline was gas-tested to 110% of MAOP (320 psig) at the time it was placed in service. The pipeline is a single feed line to a distribution system and cannot be taken out of service for the purpose of hydrostatic testing. The option of gas testing the pipeline again for any purpose was ruled out years ago because of the potential hazard of crack propagation in the event of a test rupture.

To determine whether or not this pipeline should be replaced, the operator can go through the process described below starting with Flowchart START (Figure C1 of Appendix C). Flowchart START as adapted to this particular pipeline is repeated as Figure 19 below.

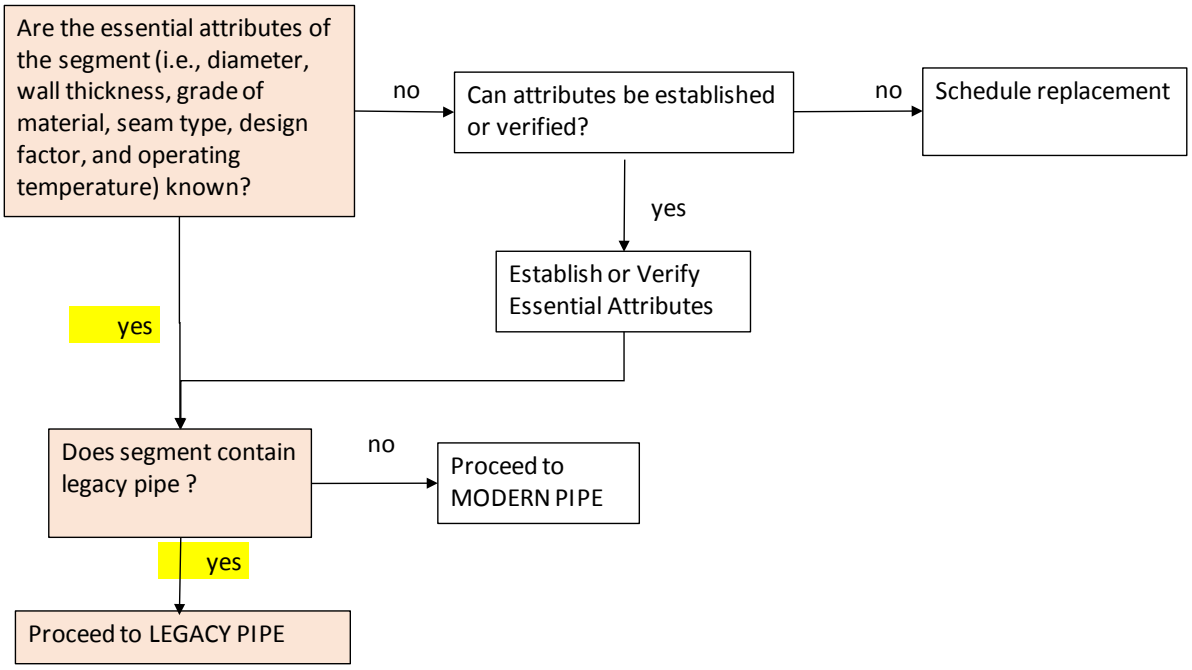


Figure 19. Start of Process to Decide Whether to Repair or Replace the Base Case Natural Gas Pipeline that is Operated at a Stress Level < 30% of SMYS

The essential attributes of this pipeline are known. The flash-welded seams mean that the pipeline is comprised of legacy pipe, so the operator may proceed to Flowchart LEGACY PIPE (Figure C2 of Appendix C). The LEGACY PIPE flowchart is shown as Figure 20 below.

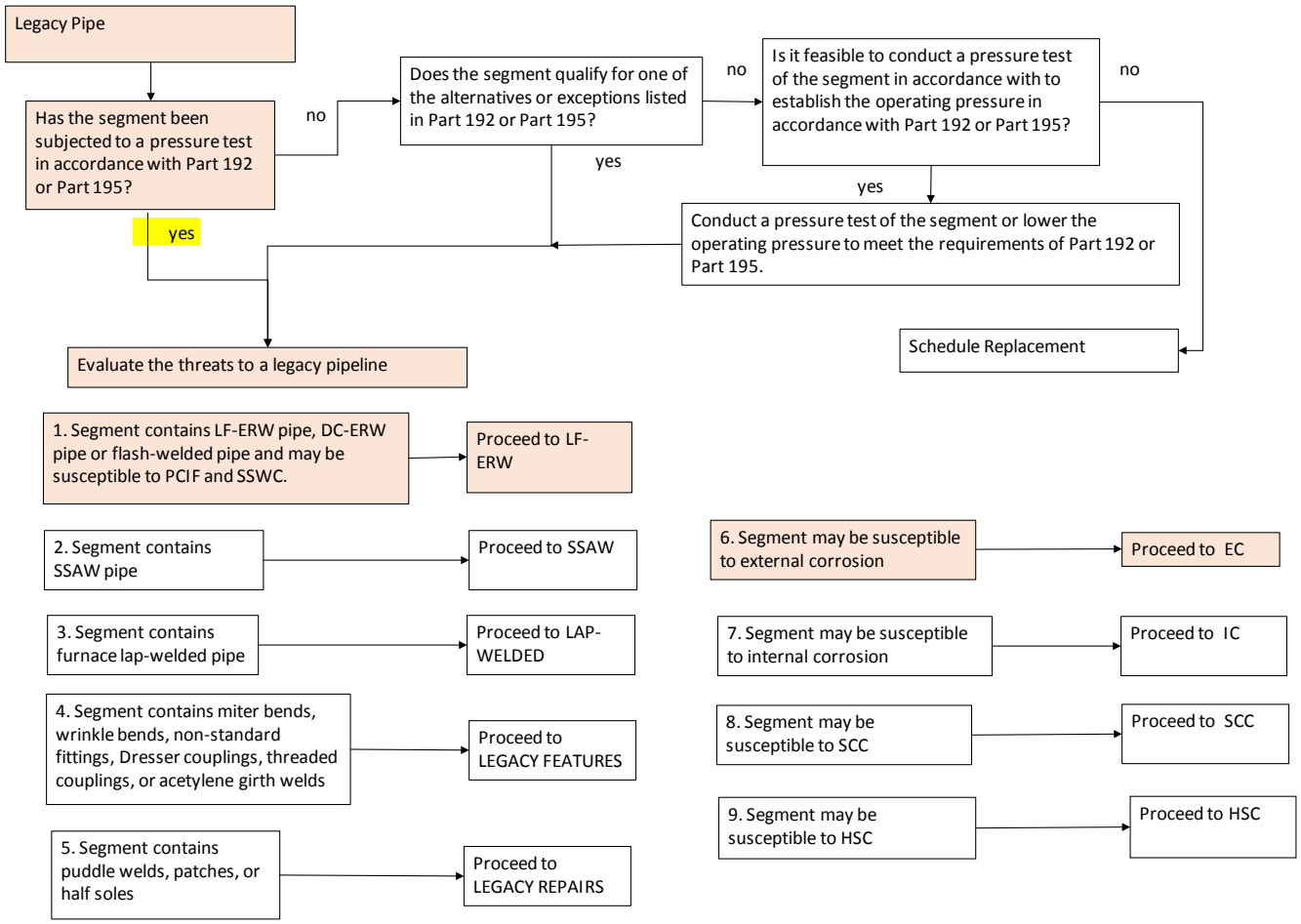


Figure 20. Threats to Address for Base Case Natural Gas Pipeline Comprised of Flash-welded Pipe that is Operated at a Stress Level < 30% of SMYS

The pipeline was gas-tested at the time of commissioning to a pressure level of 1.1 times MAOP. If the segment is entirely in a Class 1 location, this test meets the requirements of Part 192, §192.503 and §192.619. If parts of the segment are located in other class locations, this level of test may or may not be sufficient depending on the interpretation. The operator should establish whether the test does or does not comply with the regulations.

Note that a threat to seam integrity from PCIF in a natural gas transmission pipeline can be significant if the pipeline was not given a pre-service hydrostatic test, if the pre-service hydrostatic test was to a level of only 1.1 times the MAOP, or if the pipeline is operated at a maximum stress level that is much less than 72% of SMYS (i.e., 30 to 50 percent of SMYS) and has only been tested to a level of 1.25 times the MAOP. The likelihood that large manufacturing defects with failure stress levels much less than 90% of SMYS exist in this pipe is low because each piece was subjected to a test to 90% of SMYS for a period of 10 seconds by the manufacturer.

This pipeline is comprised of flash-welded pipe which can be susceptible to the seam defects that may leak or become enlarged in service from PCIF and may also be susceptible to SSWC. The threat of fatigue is improbable because of the low operating stress (<30% of SMYS) relative to the stress level of the manufacturer's hydrostatic test of each piece of pipe (90% of SMYS). Nevertheless, the operator should conduct a pressure-cycle fatigue analysis to estimate the minimum time to failure.[27]

Any pipeline may be susceptible to degradation from external corrosion. Any pipeline comprised of LF-ERW, DC-ERW, or flash-welded pipe may be susceptible to SSWC as well. Therefore, Cells 1 and 7 are highlighted in Figure 20. The pipeline contains no SSAW pipe or furnace lap-welded pipe and no miter bends, no non-standard fittings, no Dresser couplings, no threaded couplings, no acetylene girth welds, no puddle welds, no patches, and no half-soles. It does contain wrinkle bends of less than 12.5 degrees, but such wrinkle bends are permitted because the operating stress level is less than 30% of SMYS. Internal corrosion has never been noticed at any time segments of the pipe have been removed, and the pipeline carries dry natural gas with no sour components. The threat of SCC is essentially non-existent because of the low operating stress level. Also, no pipe body hard spots have been found. Therefore, the threats represented by Cells 2-6 and 8-10 need not be considered. Based on the highlighted cells, the operator of this pipeline must pursue the process of making a repair/replace decision via Flowcharts LF-ERW and EC. The first of these, Flowchart LF-ERW (Figure C3 of Appendix C) as adapted to this particular pipeline is repeated as Figures 21A and 21B below.

[27] It is possible that a hazardous liquid pipeline operated at a stress level less than 30% of SMYS may not be at risk from PCIF within its useful life. However, the degree of susceptibility depends strongly on the stress level applied in the most recent pressure test. Because the pressure cycling of liquid pipelines tends to be more aggressive than that of gas pipelines, a PCIF analysis of a liquid pipeline operated at a stress level below 30% of SMYS would seem to be even more important than it is for a gas pipeline operated at a stress level below 30% of SMYS.

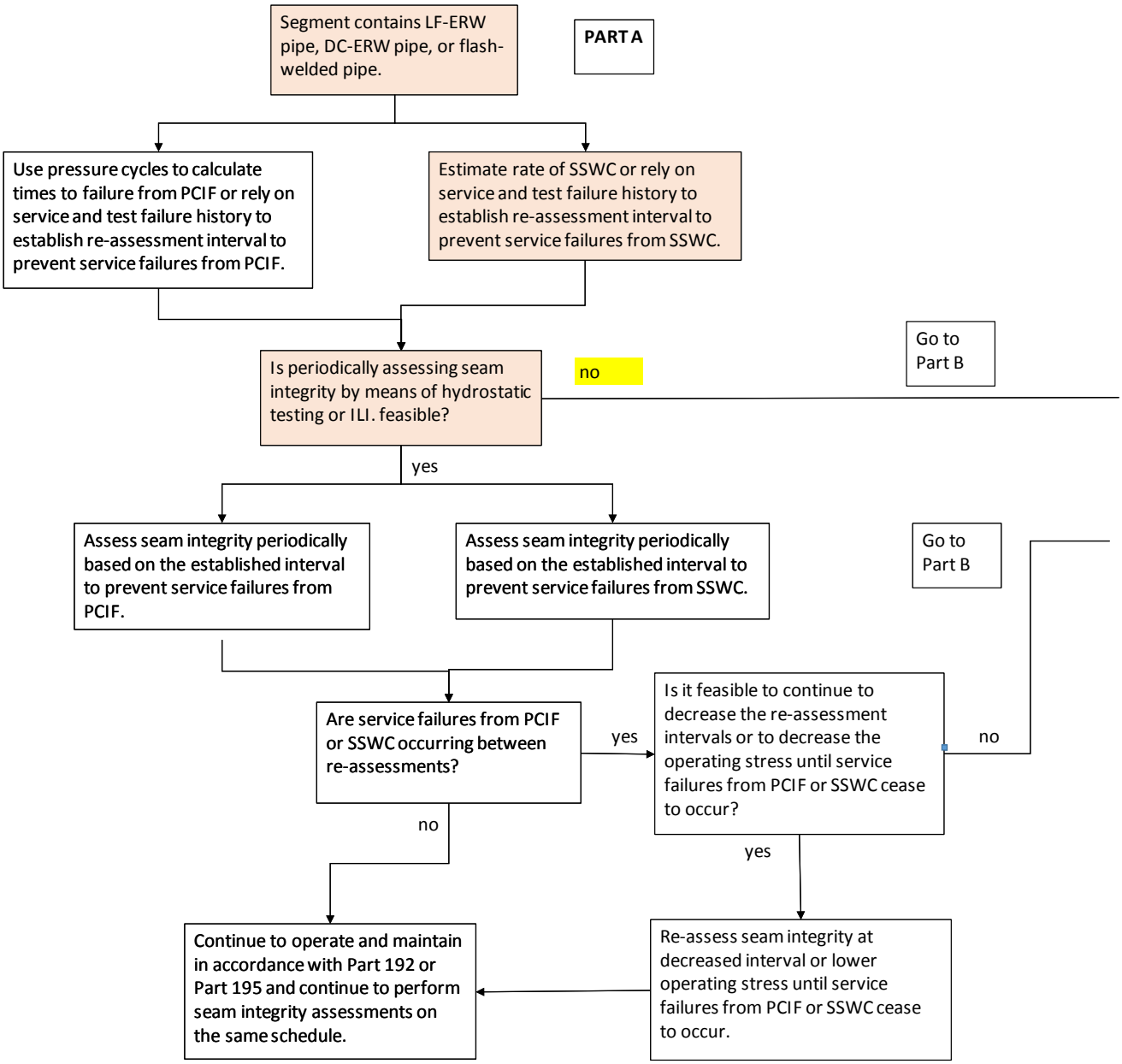


Figure 21A. Feasibility of Preventing in-Service Failures from PCIF

Because of the flash-welded seam in the pipe, it is necessary to examine the potential threat of failure from PCIF even if the threat turns out to be negligible. Figure 21A indicates that the operator should conduct a pressure-cycle fatigue analysis using actual historical pressure records from the pipeline. For such an analysis, the initial flaw sizes are usually established on the basis of the most recent pressure test. This pipeline was gas-tested prior to being placed in service to a stress level of only 32.4% of SMYS (1.1 times the maximum operating stress of 29.5% of SMYS). However, manufacturing records show that each piece of pipe was tested by the manufacturer to 90% of SMYS. The operator can rely on the manufacturer's test to 90% of

SMYS to establish the initial flaw sizes. For a conservative analysis, the use of a toughness level equivalent to a CVN energy of 200 ft lb and a flow stress equal to the specified ultimate tensile strength of the pipe is recommended.

Assume that the analysis based on a 90%-of-SMYS manufacturer's test shows that the expected minimum time to failure is 3000 years. In such a case, the operator can dismiss the threat to failure from PCIF for the conceivable life of the pipeline, and continue to operate the pipeline in accordance with Part 192 subject to the outcome of Part B shown in Figure 21B.

Note that if the operator could not prove that the pipe had been tested to 90% of SMYS, it would have been necessary to do the fatigue analysis using the 32.4% of SMYS test as the basis for establishing initial flaw sizes. In such a case, the analysis likely would show a minimum time to failure well within the expected life of the pipeline. To address that threat, the operator would either have to conduct periodic seam integrity assessments using hydrostatic testing or ILI, lower the operating pressure to the point where fatigue is no longer a threat, or schedule replacement of the pipeline after half of the estimated minimum time to failure has elapsed. The operator cannot take the pipeline out of service to conduct periodic hydrostatic testing, and the pipeline cannot accommodate ILI pigs. That would leave only the options of scheduling replacement or lowering the operating pressure. An acceptable lower operating pressure can be based on a fatigue analysis using a scaled-down pressure-cycle spectrum associated with the lower operating pressure that results in an acceptable minimum time to failure.

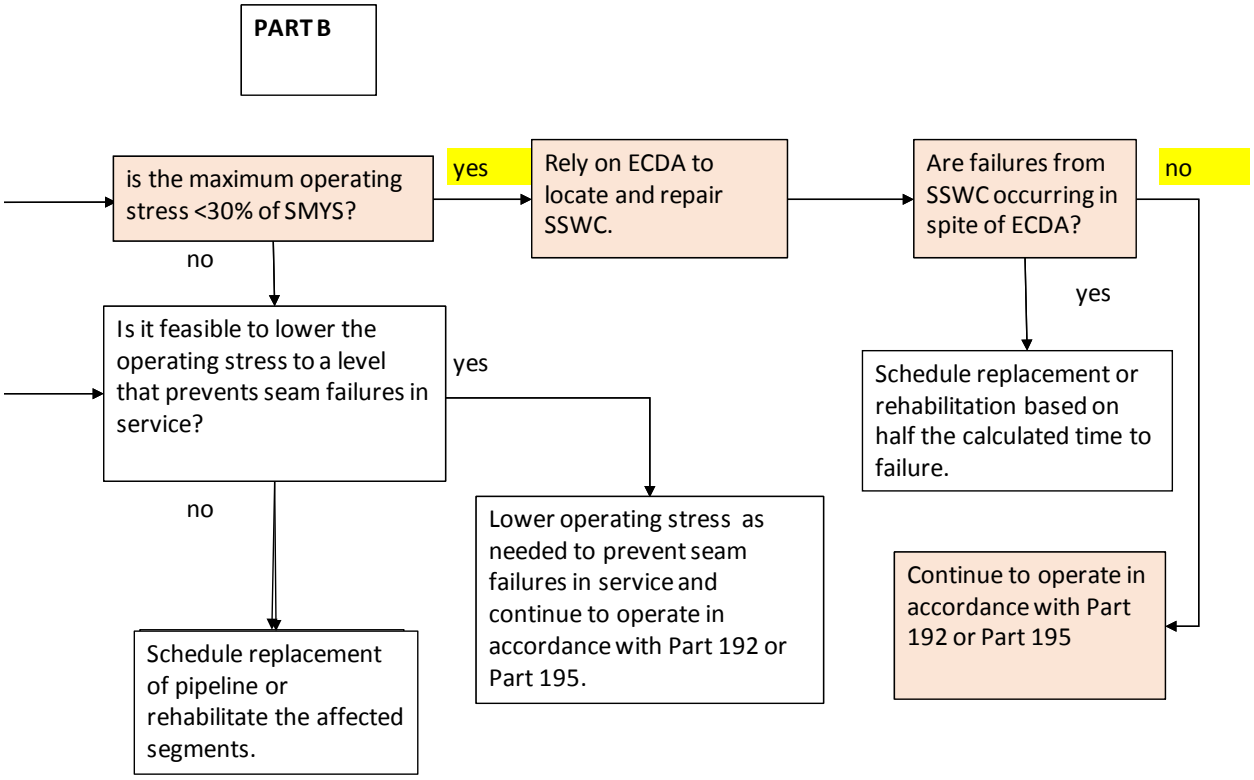


Figure 21B. Feasibility of Preventing in-Service Failures from SSWC

In the case of this pipeline, failures from both external corrosion and SSWC have occurred. The operator cannot take the pipeline out of service to conduct periodic hydrostatic testing, and the pipeline cannot accommodate ILI pigs. According to Figure 21B, the operator has the option to address the threat of SSWC by means of external corrosion direct assessment (ECDA). ECDA does not identify the presence of SSWC directly. Instead, the ECDA process identifies areas of the pipe affected by external corrosion, and direct examination of the pipe would be expected to reveal any significant SSWC that may have occurred. If by using ECDA, the operator is successful in preventing failures from SSWC, the pipeline can remain in service. As seen in Figure 22, the operator must prevent the occurrence of failures from external corrosion as well by using ECDA.

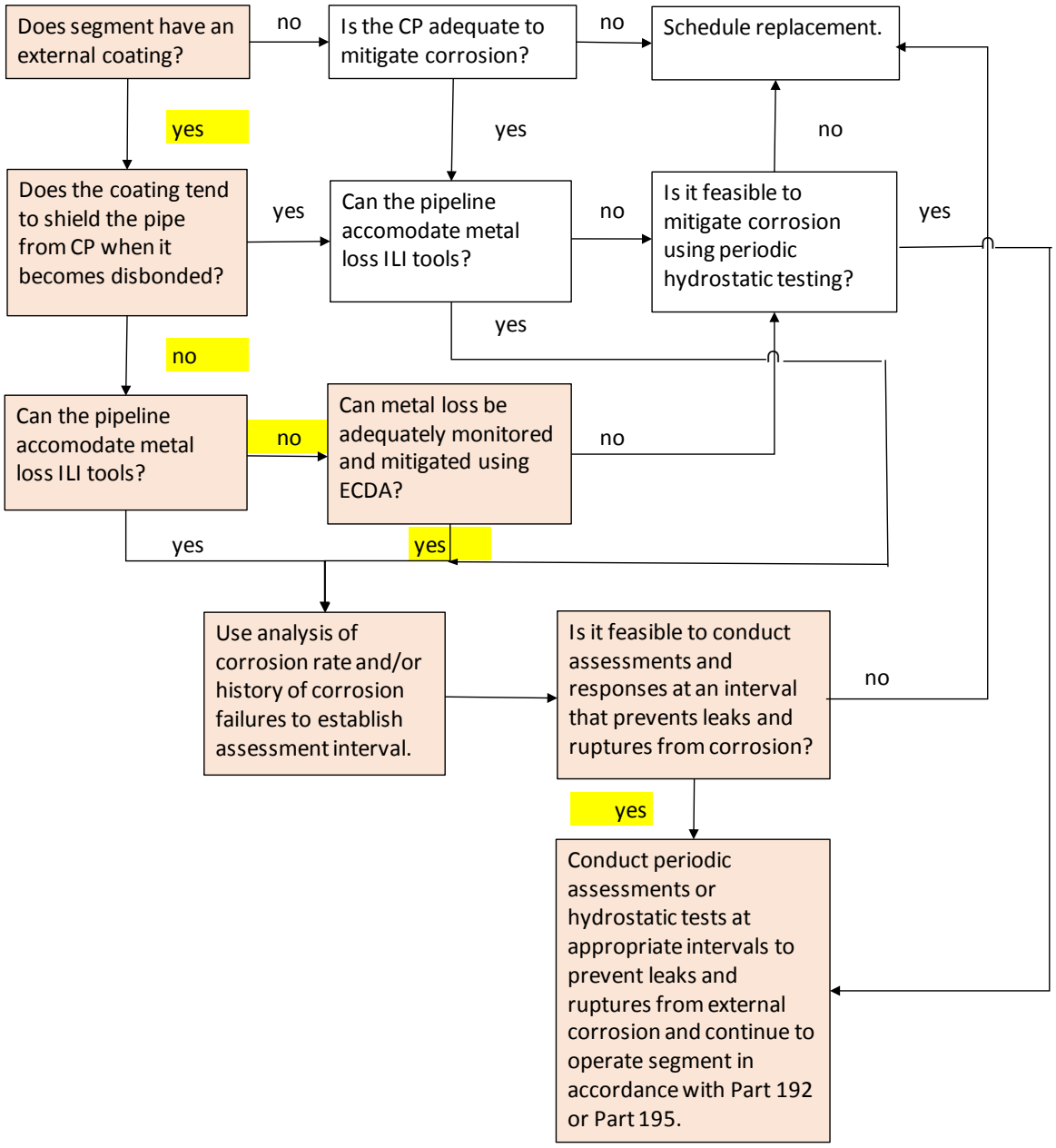


Figure 22. Feasibility of Preventing In-Service Failures from External Corrosion

The above analysis indicates that the threats to the integrity of this pipeline are being mitigated by the on-going maintenance and integrity assessment actions being taken by the operator. The question of whether or not the operator should continue to operate this pipeline versus replacing it can be made on the basis of the cost to maintain and re-assess its integrity and safety versus the cost to replace it. If these continuing costs to maintain safety and pipeline integrity are acceptable to the operator, then replacement may not be necessary.

It was noted in the data for this pipeline that it contains 50 miter bends. Miter bends are a legacy feature. However, miter bends with angle changes less than or equal to 12.5 degrees are permitted in gas pipelines that are operated at stress levels of less than 30% of SMYS[28]. Unless individual miter bends are thought to be threats to pipeline integrity at specific locations or under specific circumstances, the operator does not have to take any action with respect to the miter bends. The appropriate repair/replace strategy for the miter bends can be assessed using Flowchart LEGACY FEATURES (Figure C6 of Appendix C). For this particular pipeline, that flowchart is shown in Figure 23.

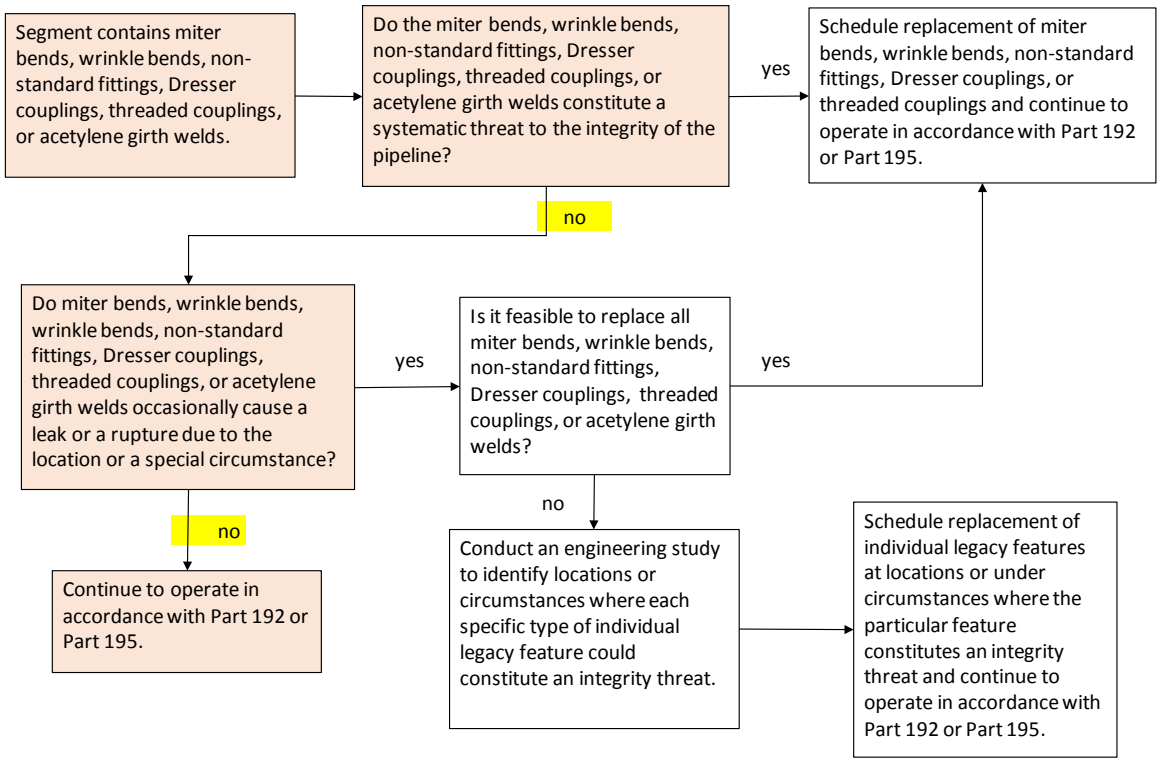


Figure 23. Consideration of the Miter Bends in the Low-Stress Gas Pipeline

As seen in Figure 23, the operator does not need to take any action as long as the miter bends have not been implicated in any leak or rupture.

Other Examples for Transmission Pipelines

The following examples are intended to show additional cases of considerations for repair/replace decisions for various situations not covered in the three base cases related to

[28] Part 192 permits angle changes at a girth weld of up to 3 degrees regardless of the operating stress level. Angle changes of up to 90 degrees are permitted in pipelines that operate at stress levels of 10% of SMYS or less.

transmission pipelines. These cases are less detailed than the base case examples, because many of the aspects of these cases were covered previously in the discussions of the base case examples. In most of these other examples, the first part of the discussion concerns a hazardous liquid pipeline. At the end of each case, the differences in decision-making considerations for high-stress and low-stress natural gas transmission pipelines, if any, are then discussed.

A Pipeline with an SSAW Seam

The Hazardous Liquid Pipeline Case

Consider a 500-mile-long, crude oil pipeline comprised of 24-inch-OD, 0.312-inch-wall, line pipe with a minimum specified yield strength of 42,000 psi, fabricated with a single-submerged-arc-welded (SSAW) seam, a type of legacy pipe. The pipeline was installed in 1948 at a time when only a tentative standard, APL STD 5LX existed for X grades of pipe. However, the pipe was purchased under an agreement whereby the manufacturer agreed to produce a material meeting the requirements of the tentative standard. The material was to have a specified minimum yield strength (SMYS) of 42,000 psi, a minimum ultimate tensile strength of 60,000 psi, and a minimum elongation of 25% in a 2-inch gage length. The agreement included limits on the following alloys in maximum percentages by weight based on check analyses: carbon: 0.33, manganese: 1.28, phosphorus: 0.115, and sulfur: 0.065. Moreover, the manufacturer agreed to meet all other requirements expressed in the 1948 tentative standard including a pressure test of each piece of pipe to a pressure level of 950 psig (87% of SMYS) for a period of 10 seconds. The pipeline was coated over-the-ditch with a coal-tar enamel and fiberglass-reinforced felt wrapping. Initially, there was no cathodic protection system, but an impressed-current cathodic protection system was installed in 1955. The pipeline is operated at an MOP of 786 psig corresponding to a hoop stress level of 72% of SMYS. The pipeline can accommodate all types of ILI tools. No legacy features such as acetylene girth welds, miter bends, wrinkle bends, patches, or half soles exist on this pipeline.

A far as records are concerned, the operator has a report from a third-party pipe mill inspection company that documents the results of tensile tests required by API Specification 5L showing that the strengths met or exceeded the agreed-upon minimum yield strength and minimum ultimate tensile strength values and that the alloy contents were within the prescribed limits. The report also documents the fact that each piece of pipe was tested to a pressure level of 950 psig corresponding to a hoop stress level of 87% of SMYS for period of 10 seconds. The operator also has records of the initial pre-service hydrostatic test to a minimum hoop stress level of 90% of SMYS and subsequent hydrostatic tests, records of all service failures, and records of ILI tool runs.

The service failure history contains incidents caused by external corrosion and seam failures from manufacturing defects. There have been no failures from internal corrosion and the prospect of internal corrosion existing seems unlikely because only non-sour crude oil has ever been shipped and because no internal corrosion has been found in any removed pieces of pipe. SSAW pipe is not known to be susceptible to SSWC. Therefore, the threats of PCIF failures at seam manufacturing defects, SCC, and external corrosion are the primary threats to be mitigated if a decision is made to keep the pipeline in service. To address these threats the operator can go through the details of the hazardous liquid pipeline flowcharts in Appendix C as was done in Base Case Example No. 1.

Figure C1 (START) directs the operator to Figure C2 (LEGACY PIPE) which, in turn directs the operator to Figure C4 (Flowchart SSAW), Figure C12 (EC) and Figure C14 (SCC). Flowchart SSAW is shown as Figure 24. Periodic seam integrity assessment is needed to mitigate against service failures from PCIF. If the pressure cycle history of this pipeline is like those of many other hazardous liquid pipelines, periodic seam integrity assessment will be needed to mitigate against service failures from PCIF within the time frame of the useful life of the pipeline. Seam integrity assessment can be done via either hydrostatic tests or successive ILI crack detection tool runs at intervals predicted by pressure-cycle fatigue analysis as explained previously.

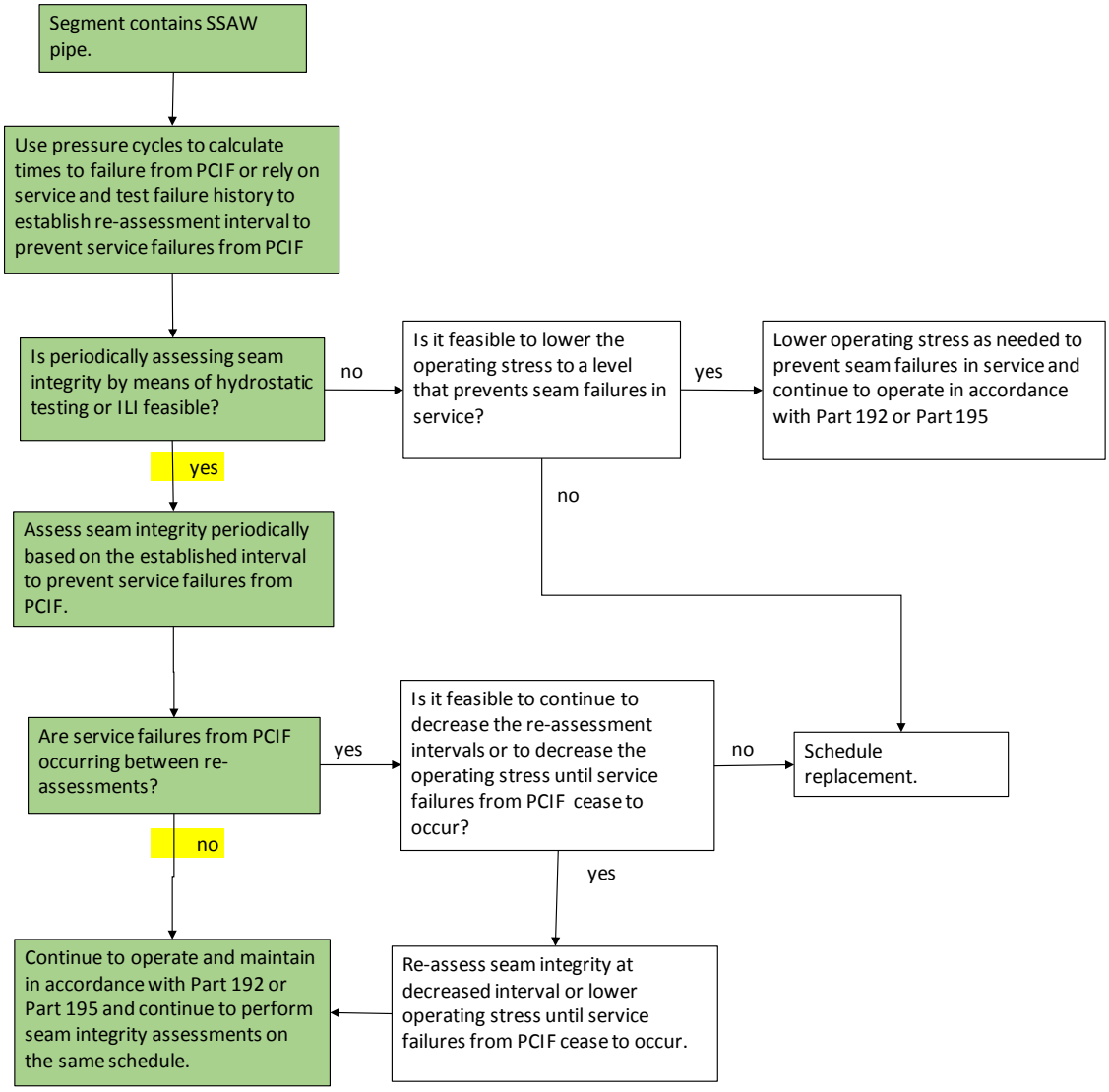


Figure 24. Flowchart for Evaluating a Repair/Replace Decision for SSAW Pipe in a Hazardous Liquid Pipeline

If the operator goes through the details of the external corrosion flowchart as was done in Base Case Example No. 1 (see Figure 10), it will be clear that periodic integrity assessment is needed to mitigate against service failures from external corrosion. Integrity assessment to mitigate an external corrosion threat can be done most effectively via successive ILI metal-loss detection tool runs at intervals predicted by the linear growth rate analysis technique explained previously.

The pipeline could also be exposed to the threat of failure from SCC. Mitigation of the SCC threat is necessary if the pipeline is to remain in service. The operator can go through the SCC flowchart as was done for the Base Case in Figure 11 to determine the appropriate means to mitigate the threat of SCC. Since there have been no incidences of SCC having been found or

having caused a failure, the operator could elect to perform periodic SCCDA inspections. If actual SCC is found (unless it can be shown to be dormant) or if SCC causes a failure, the operator should establish a program of periodic hydrostatic testing or ILI crack-tool inspections to minimize the risk of recurrences of SCC-caused failures.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, SCC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

The High-Stress Natural Gas Pipeline Case

Suppose the pipeline just described is a high-stress natural gas transmission pipeline instead of a hazardous liquid pipeline. Even if the pipe material and the operating stress level are the same, one could anticipate that some attributes and some aspects of the operating histories would differ. For example, one would expect the pressure cycles for the gas pipeline to be far less aggressive than those of the liquid pipeline. Nevertheless, the operator of the gas pipeline should go through the process described in Figure 24 to determine whether or not PCIF is a threat. Most likely, it would not be a threat within the conceivable useful life of the pipeline if the pipeline had been subjected to a pressure test to 90% of SMYS or more. If the pipeline has not ever been pressure-tested, the PCIF analysis could be based on the fact that each piece of pipe was tested by the manufacturer to a hoop stress level of 87% of SMYS.

The high-stress gas pipeline might be susceptible to high-pH SCC especially if it was operated at high discharge temperatures at some time in the past. In that case, mitigation of the SCC threat is necessary if the pipeline is to remain in service. The operator can go through the SCC flowchart as was done for the Base Case in Figure 11 to determine the appropriate means to mitigate the threat of SCC. If there have been no incidences of SCC having been found or having caused a failure or if what SCC has been found is known to be dormant, the operator could elect to perform periodic SCCDA inspections. If actual SCC is or has been found (unless it can be shown to be dormant) or if SCC causes or has caused a failure, the operator should establish a program of periodic hydrostatic testing or ILI crack-tool inspections to minimize the risk of recurrences of SCC-caused failures.

If the operator goes through the details of the external corrosion flowchart as was done in Base Case Example No. 1 (see Figure 10), it will be clear that periodic integrity assessment is needed to mitigate against service failures from external corrosion. Integrity assessment to mitigate an external corrosion threat can be done most effectively via successive ILI metal-loss detection tool runs at intervals predicted by the linear growth rate analysis technique explained previously.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of SCC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

The Low-Stress Natural Gas Pipeline Case

If the pipeline is a low-stress natural gas transmission pipeline operated at a hoop stress level of less than 30% of SMYS, the fact that the pipe was subjected to the manufacturer's test to 87% of SMYS suggests that the threat from SSAW seam integrity issues is negligible. Also, because of the relatively low operating stress, the threat of failure from SCC is negligible. However, the threat of failure from external corrosion must be addressed. In the case of a low-stress pipeline, it is usually not feasible to run ILI tools because of the low pressure, and pressure testing is too inefficient to be practical even if it were possible to take the pipeline out of service. The likely choice for mitigating the threat failure from external corrosion is ECDA.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threat of external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

A Pipeline Comprised of Furnace Lap-Welded Pipe, Constructed with Acetylene Girth Welds

The Hazardous Liquid Pipeline Case

Consider a 200-mile-long, crude oil pipeline comprised of 12.75-inch-OD, 0.375-inch-wall, furnace lap-welded pipe that was installed in 1930 by means of girth welds made via oxy-acetylene welding. Company records show that the pipe was constructed in 1930 using lap-welded steel pipe joined by acetylene girth welds. Although the operator has no records of the original specifications for the pipe, the pipe is known to be comprised of steel, not wrought iron. This and the type of girth welds have been confirmed by metallurgical examinations of test failures associated with a 1995 hydrostatic test. Therefore, because the minimum strength level for steel pipe was listed by manufacturers as 25,000 psi even before the first edition of API Specification 5L (1927), the operator has used 25,000 psi as the minimum specified yield strength of the pipe for design purposes. The design stress of the pipeline could be as high as 14,400 psi based on a design factor of 72% of SMYS and a joint factor of 0.8 for the lap-welded seam. This stress level corresponds to a pressure level of 847 psig. However, the MOP has always been 720 psig corresponding to a hoop stress level of 49% of SMYS, most likely because in the first edition of API Specification 5L (1927), the standard manufacturer's hydrostatic test of each piece of pipe was carried out at 900 psig. The pipeline can accommodate all types of ILI tools.

The pipeline was installed with no external coating. Cathodic protection was applied to the pipeline in 1955, and the cathodic protection has been upgraded a number of times by adding rectifiers in an attempt to maintain a satisfactory level of protection. The pipeline is known to have been affected by external corrosion. Records of in-service leaks prior to 1970 are incomplete, but what records exist for that period indicate that the pipeline exhibited numerous leaks. Most of these were attributed to external corrosion. Since 1970, better records have been kept. These records show that leaks from external corrosion decreased from 6 per year in 1970 to 1 per year in 1995. The drop in leakage rate is thought to have resulted from increases in the levels of cathodic protection.

An MFL ILI tool was run through the pipeline in 1995 to locate areas of severe metal loss so that they could be repaired prior to a proposed hydrostatic test. Hundreds of metal loss anomalies were located, some of which were considered to be integrity-threatening based on tool-called dimensions. Full-encirclement sleeves were applied to integrity-threatening metal loss anomalies in more than 100 locations.

Prior to 1995, in-service leaks and ruptures from causes other than external corrosion had occurred. During the period from 1970 through 1995, 20 leaks occurred that were attributable to "cracks" in the pipe body. Metallurgical analysis showed these cracks to be "burned-metal" defects, a type of manufacturing defect that can arise if the material is heated to too-high a temperature at the time the lap weld is made. Two in-service ruptures are known to have occurred between 1970 and 1995, and they were said to have been seam splits resulting from pressure surges. Also, 3 girth-weld leaks and 2 girth-weld full-circumferential ruptures occurred between 1970 and 1995. The full-circumferential ruptures occurred near one particular river crossing where flooding is believed to have undermined the pipeline causing excessive external stress on the girth welds.

The is no record of a pre-service hydrostatic test, although it is said that at the time, the practice of the pipeline's operator was to pressure test pipelines to 1.1 times MOP using the transported product, in this case, crude oil. In 1995 a hydrostatic test of the pipeline was carried out at a minimum pressure level of 900 psig to validate the MOP of 720 psig and to assess the overall integrity of the pipeline. Numerous seam splits and test breaks from burned-metal defects occurred at test pressure levels approaching 900 psig. This suggests that the pipe probably had been tested by the manufacturer to a level of 900 psig. Since the minimum test failure pressure of any defect was 850 psig, it is reasonable to assume that no significant in-service enlargement of the defects had occurred. The fact that no test ruptures or leaks from external corrosion occurred suggests that the ILI tool run and follow-up repair work successfully eliminated the integrity-threatening anomalies. Also, there were no test leaks or breaks involving acetylene girth welds. Since the 1995 hydrostatic test, no in-service failures from unbonded lap welded seams or from burned-metal defects have occurred.

The risk of a failure from SCC in this pipeline can be considered negligible because of the fact that it is operated at 49% of SMYS and because no failure from SCC has been known to have occurred. The risk of a failure from internal corrosion can be considered negligible because the pipeline has not carried sour crude oil, because no failure from internal corrosion has been known to have occurred, and because the 1995 ILI for metal loss revealed no significant amount of internal metal loss.

It might seem like the knowledge of the attributes of this pipeline are insufficient and that the pipeline should, therefore, be replaced. For example, the operator does not have mill records of the pipe manufacturing process or the mechanical test data. However, the operator has verified the type of pipe (it is lap-welded pipe) and the type of material (it is steel, not wrought iron). The operator has also conducted a pressure test of the pipeline in 1995 that establishes the MOP of the pipeline. Knowing these items, the operator can continue to operate the pipeline as long as continuing integrity assessment is feasible.

In 2002 the operator began an integrity management program for the HCA's on this pipeline. Because the HCA's on the pipeline are numerous and scattered, the operator decided to conduct metal loss integrity assessments of the whole pipeline even though the total HCA mileage is 30 miles. Thus, the whole pipeline has been inspected for metal loss via an MFL tool three times since 1995. The inspections were carried out in 2002, 2007, and 2012. In all three inspections metal loss areas were found, the most severe indications were excavated and examined, and full-encirclement sleeves were installed at locations judged to be integrity-threatening. The trend in the numbers found in each successive inspection is fairly level. This suggests that the corrosion is not being completely mitigated, but it does appear that the periodic inspections allow for timely repairs to areas of developing metal loss, and it is expected that future in-service failures from corrosion can be prevented.

For seam integrity assessment purposes, the operator has carried out hydrostatic tests of only the HCA portions of the pipeline in 2002, 2007, and 2012. The tests have been carried out at a minimum pressure of 900 psig. Test failures have occurred each time as pressure levels approached 900 psig from seam defects and burned-metal defects, but neither the failure pressure levels nor subsequent metallurgical examinations have reveal any evidence of growth of the defect in service.

The risk of a failure involving an acetylene girth weld seems to be confined to the particular river crossing where the two full-encirclement ruptures had occurred in the period between 1970 and 1995. Even though no failures of girth welds at that crossing had occurred since 1995, the operator replaced the entire crossing in 2002 with modern coated pipe with electric-arc girth welds.

If the operator of this pipeline wants to evaluate the economics of replacing this pipeline as opposed to continue repairing it, the flowcharts in Appendix C could be used as a guide. The first chart, Figure C1 (START), would steer the operator to Figure C2 (LEGACY PIPE). Figure C2 then steers the operator to Figure C5 (LAP WELDED) to assess the responses to possible lap-welded pipe anomalies, Figure C6 (LEGACY FEATURES) to assess the responses to acetylene girth welds, and Figure C12 (EC) for responses to external corrosion. Flowchart (LAP WELD) for this pipeline is shown in Figure 25.

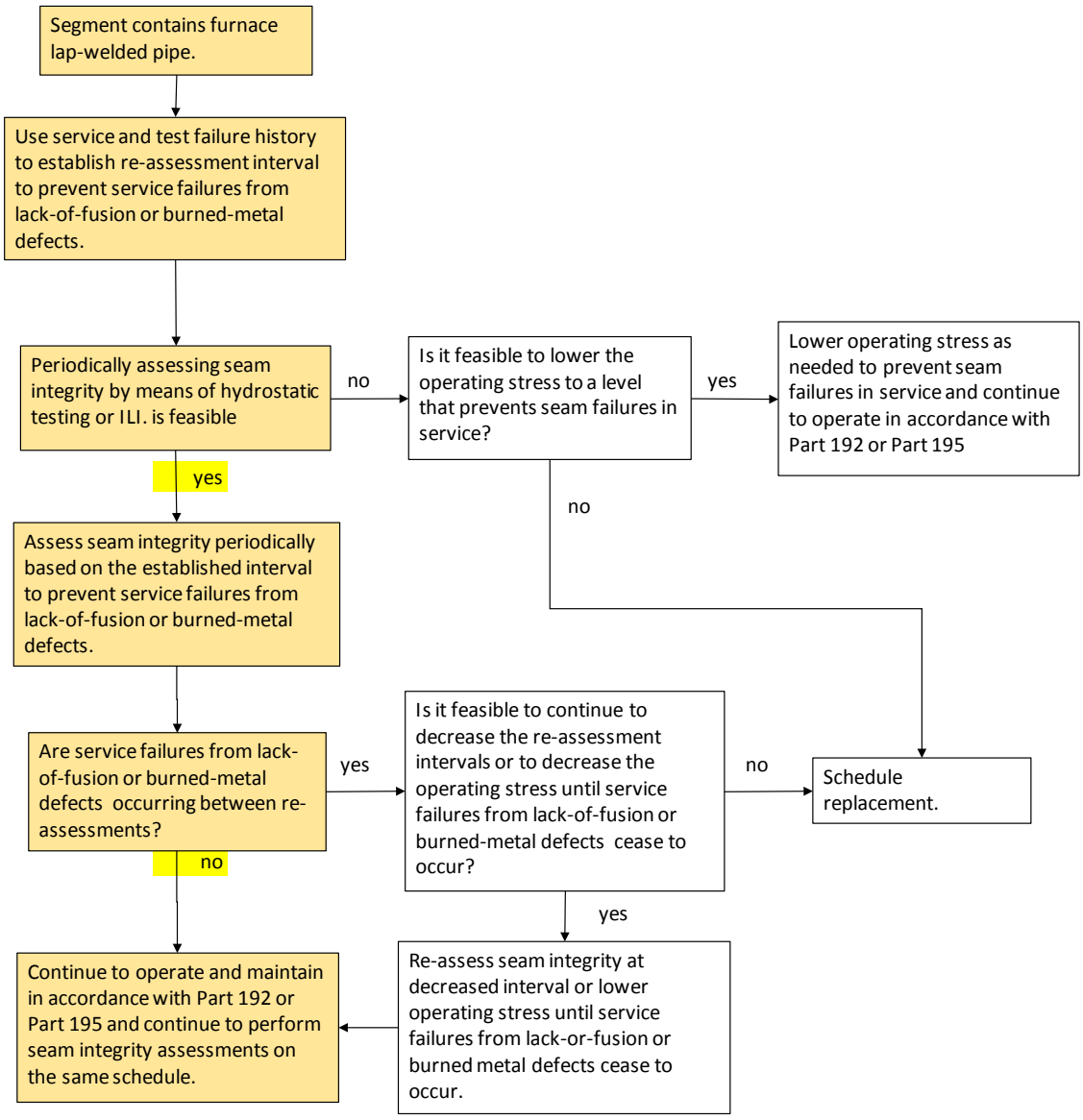


Figure 25. Flowchart for Evaluating a Repair/Replace Decision of Furnace Lap-Welded Pipe in a Hazardous Liquid Pipeline

If the pressure cycle history of this pipeline is like those of many other hazardous liquid pipelines, periodic seam integrity assessment will be needed to mitigate against service failures from PCIF within the time frame of the useful life of the pipeline even though the pipeline is operated at an MOP corresponding to 49% of SMYS. Seam integrity assessment can be done via hydrostatic tests even though there is very little if any published experience with the effects of PCIF on furnace lap-welded pipe. A hydrostatic test establishes the worst case family of surviving defects that could grow by PCIF. Whether or not successive ILI crack detection tool runs would reveal the presence and size of the two common lap-welded pipe manufacturing defects (unbonded seams and burned-metal defects) is not known. It is conceivable that such tools could be used effectively to assess the seam integrity of lap-welded pipes, but it is doubtful that ILI crack detection technology has been used to a great enough extent in lap-welded pipe at this time to establish a track record. In any case, the intervals between assessments are predicted by pressure-cycle fatigue analysis as explained previously.

From the standpoint of the legacy girth welds, the operator can utilize Flowchart LEGACY FEATURES which is show below as Figure 26.

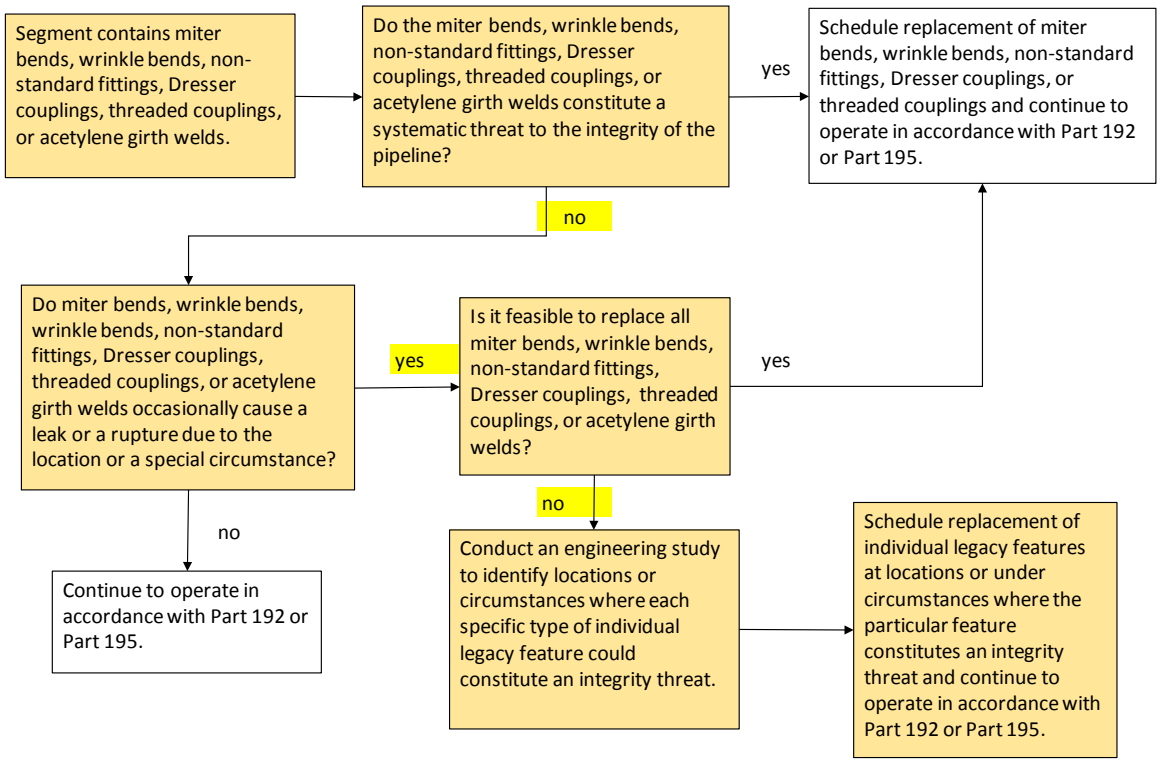


Figure 26. A Process by Which the Operator Can Deal with Acetylene Girth Welds

The acetylene girth welds, except for a few, have performed adequately. It is not feasible to change out all of them. The operator has done an engineering study based on the location of

two girth weld ruptures at a particular river crossing. As a result of the study the crossing was replaced with new pipe using electric-arc-welded girth welds. No other action was needed.

If the operator goes through the details of the external corrosion flowchart as was done in Base Case Example No. 1 (see Figure 10), it will be clear that periodic integrity assessment is needed to mitigate against service failures from external corrosion. Integrity assessment to mitigate an external corrosion threat can be done most effectively via successive ILI metal-loss detection tool runs at intervals predicted by the linear growth rate analysis technique explained previously.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace the pipeline. From the standpoint of the legacy acetylene girth welds the operator may continue to replace particular locations where such welds are vulnerable to failure in order to avoid replacing the whole pipeline.

The High-Stress Natural Gas Pipeline Case

If the same lap-welded pipeline discussed above transports natural gas at an MAOP of 720 psig instead of crude oil at an MOP of 720 psig and is regulated under Part 192 instead of Part 195, the main thing that would change with respect to a repair/replace decision would be the likelihood that PCIF would not constitute a significant threat within the life of the pipeline. As a result continuing seam integrity assessment especially in the form of hydrostatic testing would become unnecessary. The cost of continuing to repair the pipeline instead of replacing it, therefore, would be less than in the case of the liquid pipeline. The costs of continuing to inspect for corrosion and the costs associated with monitoring and remediating external forces that could cause failure of an acetylene girth weld in the gas pipeline likely would be about the same as those for the same activities in the liquid pipeline.

The Low-Stress Natural Gas Pipeline Case

If the same lap-welded pipeline discussed above transports natural gas at an MAOP of 400 psig (27% of SMYS) instead of crude oil at an MOP of 720 psig and is regulated under Part 192 instead of Part 195, the main thing that would change with respect to a repair/replace decision would be the likelihood that PCIF would not constitute a significant threat within the life of the pipeline. As a result continuing seam integrity assessment especially in the form of hydrostatic testing would become unnecessary. The cost of continuing to repair the pipeline instead of replacing it, therefore, would be less than in the case of the liquid pipeline. The costs of continuing to inspect for corrosion and the costs associated with monitoring and remediating

external forces that could cause failure of an acetylene girth weld in the gas pipeline likely would be about the same as those for the same activities in the liquid pipeline.

In the case of a low-stress pipeline it is usually not feasible to run ILI tools because of the low pressure, and pressure testing is too inefficient to be practical even if it were possible to take the pipeline out of service. A possible choice for mitigating the threat of failure from external corrosion is ECDA, though ECDA is generally not very effective on a bare pipeline. The expense of trying to mitigate corrosion on such a pipeline using ECDA might cause the operator to consider replacement of the pipeline.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threat of external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

A Pipeline Comprised of Pipe with a DSAW Seam

The Hazardous Liquid Pipeline Case

Consider an 1100-mile-long refined products pipeline comprised of 36-inch-OD, 0.281-inch-wall, API 5LX52 line pipe with a double-submerged-arc seam. The operator has copies of mill certificates indicating that the material properties and chemistries met or exceeded the minimum requirements of API Specification 5LX, 21st Edition, March 1965. The pipeline was installed in 1966. It was coated over-the-ditch with a single-layer coating consisting of a polyethylene outer wrap with a butyl-rubber mastic backing. An impressed-current cathodic protection system was installed and activated within the first year of operation of the pipeline. The pipeline is operated at an MOP of 584 psig corresponding to a hoop stress level of 72% of SMYS. The pipeline can accommodate all types of ILI tools. No legacy features such as acetylene girth welds, miter bends, wrinkle bends, non-standard fittings, Dresser couplings, threated couplings, patches, or half soles exist on this pipeline.

Records indicate that the pipeline was subjected to a pre-service hydrostatic test to a minimum hoop stress level of 90% of SMYS in 1966. No additional integrity assessments were done until an in-service rupture occurred in 1982 from an area of external corrosion in the body of the pipe. Following the rupture a low-resolution MFL ILI tool was used to locate other areas of external corrosion. Several hundred anomalies were found, and 20 of those deemed to be the most severe were excavated and evaluated resulting in the installation of 20 full-encirclement sleeves.

In 1989, another in-service rupture of the pipeline occurred. This rupture was found to have been caused by PCIF. The origin was a railroad fatigue crack[29] along the toe of the longitudinal seam. The pipe had been shipped from the pipe mill to the marshalling area by rail. The D/t ratio of 128 made this pipe quite susceptible to deflection from point loading and, hence, from railroad fatigue. The operator conducted a fatigue analysis to determine the locations along the pipeline where PCIF is most likely to occur. In 1990, the operator then subjected those segments of the pipeline to hydrostatic tests to stress levels ranging from 90% to 100% of SMYS. During the test two more locations of railroad fatigue cracks were revealed by causing test failures. In both cases it appeared that the railroad fatigue portions of the cracks were being extended by PCIF, suggesting that both might have failed in service in the future. No other failures from time-dependent defects occurred during the test.

In 1995, a high-resolution MFL tool was used to inspect the pipeline for corrosion-caused metal loss. While hundreds of anomalies were located, only 20 warranted excavation and examination. All of these anomalies were repaired by means of composite wraps.

In 1999, another in-service rupture of the pipeline occurred. This rupture was caused by narrow axial external corrosion (NAEC) along the longitudinal seam. When the 1995 ILI data were reviewed, this anomaly did not standout as being anywhere near as deep as the anomaly that failed. Its failure stress calculated on the basis of the dimensions from the 1995 ILI data was over 100% of SMYS. While it is possible that the anomaly could have grown sufficiently between 1995 and 1999 to fail at the maximum operating stress of 72% of SMYS, the problem more likely is the result of the ILI technology (longitudinal-field MFL) not being capable of accurately sizing long, narrow anomalies. In 2000, the pipeline was again subjected to an ILI metal-loss inspection, but this time a circumferential-field MFL (CMFL) tool was run. The circumferential-field MFL was a new development, and it possesses capabilities for accurately sizing narrow axial anomalies. When this tool was run, several locations of NAEC that were considered to be integrity-threatening were found and remediated, none of which likely could have been correctly identified without the CMFL tool. It is noted that the NAEC phenomenon is associated with the fact that the tape coating on the pipeline tended to form a "tent" over the crown of the DSAW seam. In places, ground water penetrated into these narrow voids along the toe of the weld, and corrosion took place resulting in these long and narrow anomalies. The NAEC phenomenon is rarely found on pipelines with other types of coating such as coal tar

[29] A railroad fatigue crack arises during rail shipment of pipe. The most common case involves a crack developing at the toe of the longitudinal seam of a piece of DSAW pipe that has been improperly loaded onto the rail car such that the crown of the seam weld is the point of contact with one of the wood bearing strips supporting the pipe. See API 5L1: Recommended Practice for Railroad Transportation of Pipe.

enamel or fusion-bonded epoxy, because voids at the toes of the DSAW seam normally do not exist in conjunction with these types of coatings.

In 2002, the operator instituted an integrity management plan for HCAs along the pipeline. The plan called for ILI metal loss inspections, ILI inspections using CMFL technology to monitor for NAEC, and ILI crack-tool inspections to verify seam integrity from the standpoint of PCIF. The intervals were set at 5 years for these inspections, but the start times were staggered such that only one type of tool is used in any given year. The operator also decided to inspect 100% of the pipeline with each type of tool even though HCAs account for only 30% of the mileage. The HCAs are scattered along the pipeline making it impractical to inspect only the HCAs.

From the standpoint of a repair/replace decision, one can see that the primary threats to this pipeline that must be mitigated, if it is to remain in service, are PCIF, external corrosion, and NAEC. The operating stress level and the type of coating also render it susceptible to SCC even though no failure from SCC has occurred. The pipeline does not transport a corrosive product, so there is no significant threat associated with internal corrosion. Besides, if the operator continues to use high-resolution MFL tools to search for metal loss, any internal corrosion that may develop will be revealed.

If the time comes when the operator wants to consider replacement of this pipeline, the decision can be facilitated by means of the hazardous liquid pipeline flowcharts in Appendix C. Figure C1. Figure C1 (START), steers the operator to Figure C8, MODERN PIPE. It is clear that the pipeline has met the pressure test requirements of Part 195, and the flowchart tells the operator to proceed to Figure C10 (DSAW), Figure C12 (EC), and Figure C14 (SCC). Flowchart DSAW addresses the issues related to the fact that this pipeline is comprised of DSAW pipe. Flowchart DSAW is shown below as Figure 27.

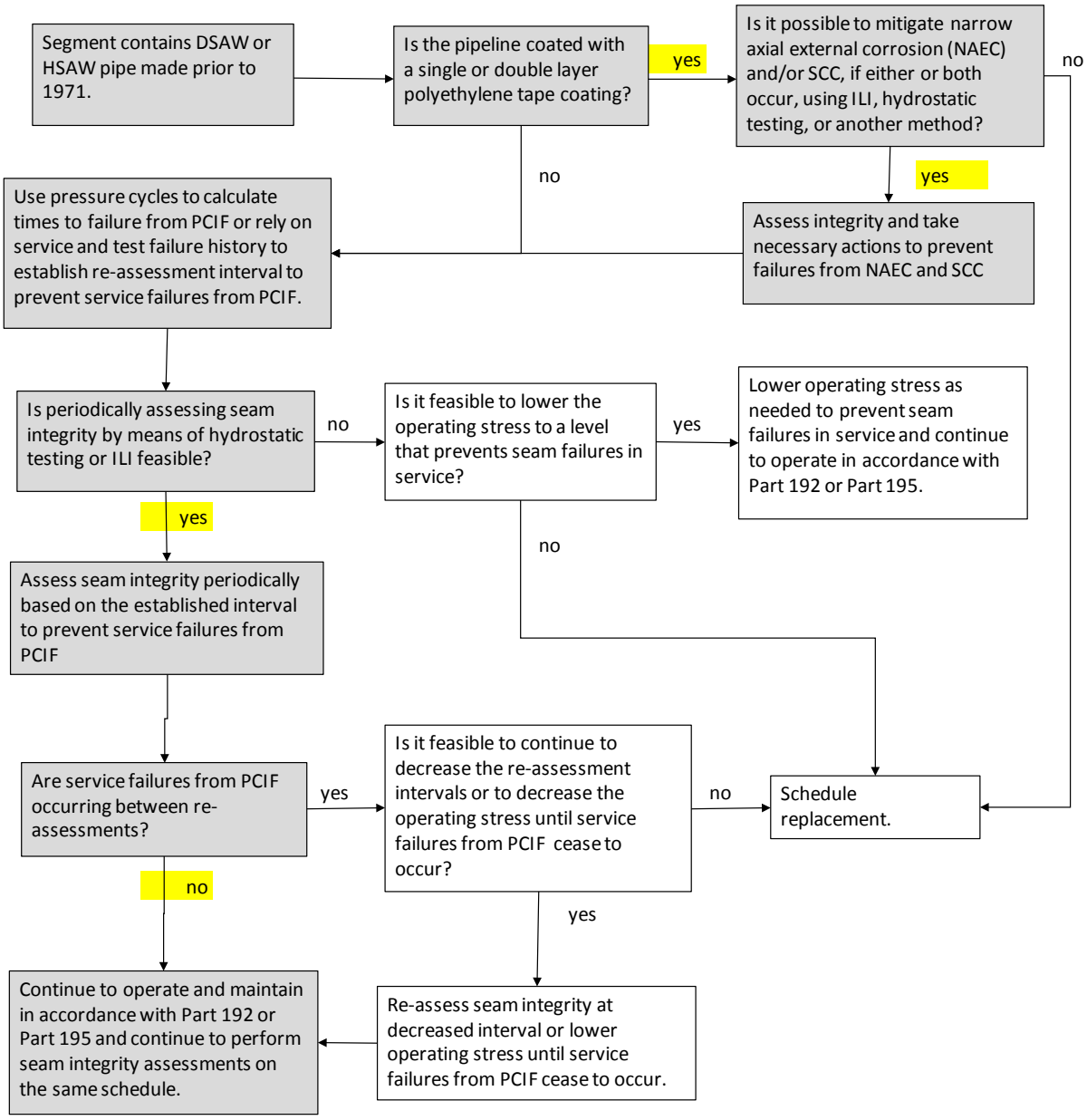


Figure 27. Flowchart for Evaluating a Repair/Replace Decision for DSAW Pipe in a Hazardous Liquid Pipeline

The first step for a pipeline comprised of DSAW pipe is to establish whether or not the coating is of a type that "tents" over the crown of the weld. In this pipeline it does, making the pipe vulnerable to NAEC (one such failure has already occurred). The single-layer polyethylene coating also raises the risk of occurrence of SCC because of its tendency to shield the pipe from cathodic protection if it becomes disbonded. The operator must mitigate the risks of SCC, NAEC, and external corrosion and perform appropriate periodic integrity assessments in a timely manner to prevent failures. Note that a CMFL tool needs to be used to assess for NAEC.

A prior in-service failure and two hydrostatic test failures from PCIF mean that periodic seam integrity assessment will be needed to mitigate against service failures from PCIF. A fatigue analysis using the pressure cycle history of this pipeline can be used to estimate the length of interval between integrity assessments. Seam integrity assessment can be done via either hydrostatic tests or successive ILI crack detection tool runs at intervals predicted by pressure-cycle fatigue analysis as explained previously. Though the re-assessment interval might not be the same as for PCIF, the integrity of the pipeline from the standpoint of SCC can also be assessed periodically via either hydrostatic testing or ILI crack detection tool runs.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost of performing required integrity assessments over the life of the pipeline with the cost of replacement.

The High-Stress Natural Gas Pipeline Case

Suppose the pipeline just described is a high-stress natural gas transmission pipeline instead of a hazardous liquid pipeline. The comparable 30-inch-OD, X52 DSAW gas pipeline of the 1966 era would likely be comprised of a somewhat thicker material such as 0.375-inch-wall pipe and would have a correspondingly higher operating pressure (MAOP = 936 psig) for the 72%-of-SMYS operating stress level. Assume that the gas pipeline also was coated with the same type of coating, i.e., a polyethylene coating with a butyl rubber mastic backing. One could anticipate that it will be exposed to same degree to the risks of failures from NAEC, SCC, and external corrosion.

Because this pipe has a D/t ratio of 80, it is much less likely to have sustained railroad fatigue than the pipe in the hazardous liquid example (if, indeed, it was shipped by rail). However, if it was shipped by rail and was loaded improperly on rail cars, it is not immune from railroad fatigue as one can see by reading API 5L1. If one assumes that the pipeline was given a pre-service hydrostatic test to a minimum stress level of 90% of SMYS, any surviving railroad fatigue cracks would be of no more concern than any other potential manufacturing defect.

One would expect that the pressure cycles for the gas pipeline would be far less aggressive than those of the liquid pipeline. That most likely means that PCIF would not be a threat within the conceivable useful life of the pipeline if the pipeline had been subjected to a pressure test to 90% of SMYS or more. If the pipeline has not ever been pressure-tested, the PCIF analysis could be based on the fact that each piece of pipe was tested by the manufacturer to a hoop stress level of 90% of SMYS. The likelihood that large manufacturing defects with failure stress levels much less than 90% of SMYS exist in this pipe is low because each piece was subjected to a test to 90% of SMYS for a period of 10 seconds by the manufacturer.

Note that the manufacturer's hydrostatic test does not provide assurance with regard to railroad fatigue cracks. Therefore, if no hydrostatic test has ever been performed in situ on such a pipeline, either a test to 90% of SMYS would have to be conducted or a reliable ILI crack-detection tool would have to be run to assure that no railroad fatigue crack exists that could cause a failure at the MAOP of the pipeline.

The operator can go through the appropriate flowcharts in Appendix C: Figure C1 (START) and Figure C8 (MODERN PIPE). The pipeline has been pressure tested in compliance with Part 192, so the operator needs to address the threats of PCIF, NAEC, EC, and SCC using Figure C10 (DSAW), Figure C12 (EC), and Figure C14 (SCC). Mitigation of PCIF may be unnecessary if fatigue analysis shows that failure from PCIF is not likely to occur within the useful life of the pipeline. Mitigation of NAEC requires periodic integrity assessment using an appropriate ILI technology such as a CMFL tool. If SCC is or has been found (unless it can be shown to be dormant) or if SCC causes or has caused a failure, the operator should establish a program of periodic hydrostatic testing or ILI crack-tool inspections to minimize the risk of recurrences of SCC-caused failures.

If the operator goes through the details of the external corrosion flowchart as was done in Base Case Example No. 1 (see Figure 10), it will be clear that periodic integrity assessment is needed to mitigate against service failures from external corrosion. Integrity assessment to mitigate an external corrosion threat can be done most effectively via successive ILI metal-loss detection tool runs at intervals predicted by the linear growth rate analysis technique explained previously. However, mitigation of the threat of NAEC requires the periodic use of a CMFL tool or a hydrostatic test.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, NAEC, SCC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

Consider a hypothetical case in which the pipeline in this example could not accommodate ILI tools. The mitigative options for the operator in this case would be limited to hydrostatic testing and SCCDA. ECDA cannot be used on this pipeline because the coating shields the pipe from cathodic protection when it disbonds. The operator has the following choices and should make the decision based on risk and consequence factors associated with each integrity mitigation alternative taking into consideration cost impact.

- Conduct periodic hydrostatic tests to address the threats from NAEC and SCC.
- Recoat the pipeline with a coating that virtually eliminates the risk of NAEC and possibly SCC as well.
- Make the pipeline capable of handling at least some types of ILI tools.

- Replace the pipeline.

The Low-Stress Natural Gas Pipeline Case

It is likely that a low-stress natural gas transmission pipeline comprised of the same pipe as discussed previously in conjunction with the high-stress natural gas pipeline will be much shorter than 1100 miles. Otherwise, however, such a pipeline conceivably could be comprised of 30-inch-OD, 0.375-inch-wall, X52, DSAW pipe. If such a pipeline is operated at a hoop stress level of less than 30% of SMYS, the fact that the pipe was subjected to the manufacturer's test to 90% of SMYS suggests that the threat from PCIF is negligible. Also, because of the relatively low operating stress, the threat of failure from SCC is negligible. However, the threat of failure from NAEC and external corrosion must be addressed. If the pipeline cannot accommodate ILI tools because of the low operating pressure (<390 psig) or if there is any other reason it is not piggable, MFL and CMFL tools could not be used to mitigate these threats. Note also, that ECDA cannot be relied upon because of the external coating that shields the pipe from cathodic protection when it becomes disbonded. Thus, without conducting periodic hydrostatic tests, the operator cannot be confident that these threats are being mitigated.

The operator of this pipeline may have to do one of the following:

- Lower the operating pressure to reduce the threat of rupture from corrosion.
- Use alternative technology to assess for corrosion (e.g., a crawler-type tool).
- Take the pipeline out of service periodically for hydrostatic testing.
- Recoat the pipeline so that ECDA can be applied.
- Replace the pipeline.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of NAEC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace or exercise one of the bullet-point options.

A Pipeline Comprised of Pipe with an HF-ERW Seam

The Hazardous Liquid Pipeline Case

Consider a 900-mile-long crude oil pipeline comprised of 16-inch-OD, 0.250-inch-wall, API 5LX52 line pipe with a HF-ERW seam. The pipeline was installed in 1965. It was coated over-the-ditch with a coal tar enamel coating. An impressed-current cathodic protection system was installed and activated within the first year of operation of the pipeline. The pipeline is operated at an MOP of 1170 psig corresponding to a hoop stress level of 72% of SMYS. It can accommodate all types of ILI. Note that this pipeline is very similar to the pipeline in Base Case

Example 1. The only difference is that it is comprised of high-frequency-welded ERW pipe made in 1965 instead of low-frequency-welded ERW pipe made in 1953.

In 1965 and up into the 1980's much of the skelp rolled for ERW pipe was made using conventional carbon-manganese steel with little or no sulfur control made in open-hearth furnaces and cast into ingots. Moreover, the coil-leveling, can-forming, and resistance-welding stands for making both HF-ERW and LF-ERW at the time were similar. Thus, the main (and possibly the only) difference between HF-ERW and LF-ERW during the period from 1960 until the complete conversion to basic-oxygen steel making in the 1980s was the nature of the weld and heat-affected-zone. LF-ERW seams where characterized by large grain size from grain-coarsening during welding, whereas with HF-ERW seams, the grain size tended to be much like that in the plate material. As a result the bond line region of an HF-ERW material tends to behave in a ductile manner when broken whereas that of an LF-ERW seam tends to behave in a brittle manner when broken. In spite of this clear advantage, HF-ERW materials often were not necessarily of better quality than LF-ERW materials when it came to hook cracks since the sulfur contents did not change significantly until the 1980s. Hook cracks arise from manganese-sulfide inclusions and sulfur contributes to the susceptibility of ERW pipe to SSWC. Therefore, one must assume that early HF-ERW pipe is susceptible to the threats of PCIF and SSWC. Once that assumption is made, the process for making a repair/replace decision is identical to that presented in Base Case Example No. 1. Instead of being directed to Figure C2 (LEGACY PIPE) and Figure C3 (LF-ERW) for legacy pipe, however, the operator is directed to Figure C8 (MODERN PIPE) and Figure C9 (HF-ERW). Flowchart HF-ERW is shown in Figure 28.

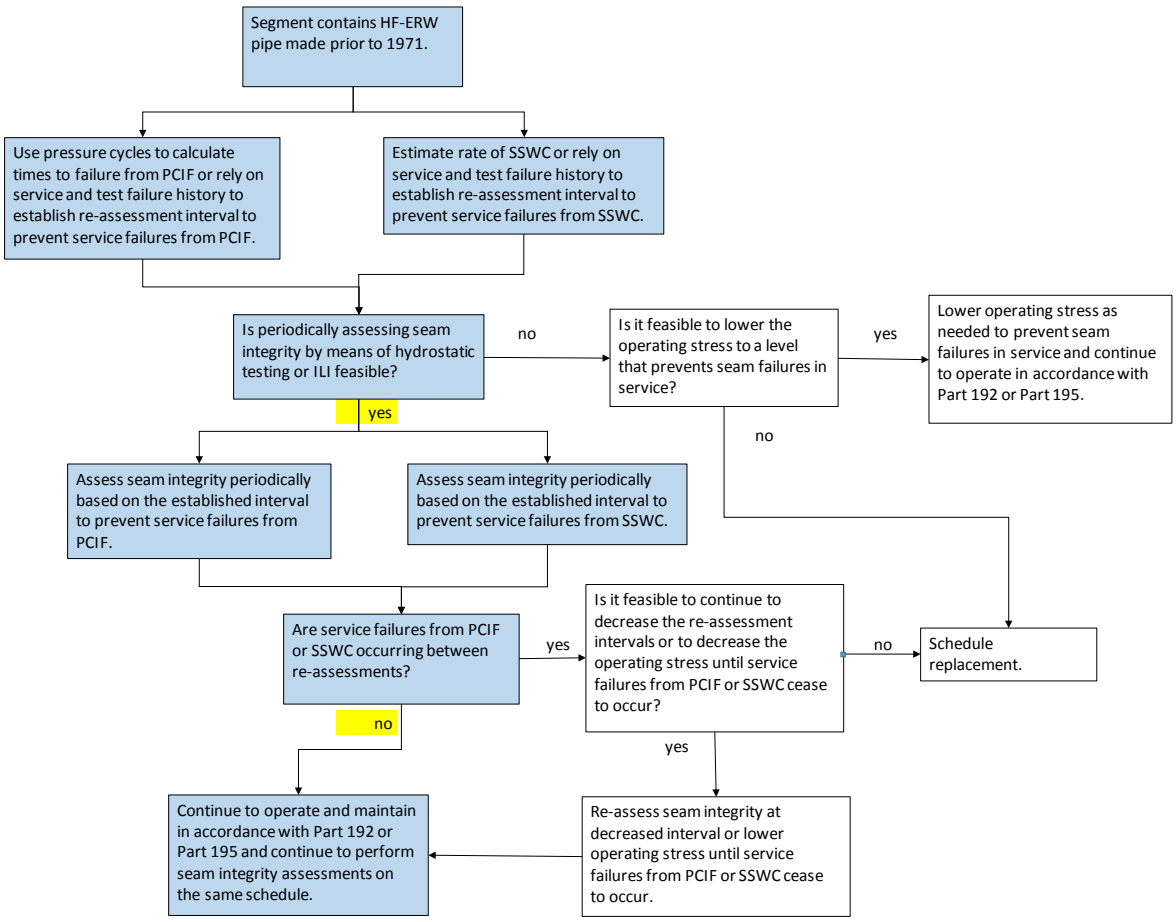


Figure 28. Flowchart for Evaluating a Repair/Replace Decision for HF-ERW Pipe in a Hazardous Liquid Pipeline

It is necessary to mitigate the threats of PCIF and SSWC in this pipeline just as it is in a pipeline comprised of LF-ERW pipe because, the HF-ERW pipe made prior to 1971 was no less susceptible to these phenomena as explained above.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, SCC, and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

The High-Stress Natural Gas Pipeline Case

Since HF-ERW pipe was rarely ever made in sizes above 24-inch, this case is not exactly the same as Base Case Example No. 2. However, if one assumes that a 900-mile-long high-stress natural gas pipeline is comprised of 16-inch-OD, 0.250-inch-wall, X52 HF-ERW pipe operated at an MAOP of 1170 psig (72% of SMYS), then except for the pipe size and operating pressure differences, the process for making a repair/replace decision is identical to that presented in Base Case Example No. 2. Instead of being directed to Figure C2 (LEGACY PIPE) and Figure C3

(LF-ERW) for legacy pipe, however, the operator is directed to Figure C8 (MODERN PIPE) and Figure C9 (HF-ERW). The likelihood is that a pressure cycle fatigue analysis will show that this pipeline is not likely to experience a failure from PCIF within the useful life of the pipeline. However, the pipeline is possibly exposed to the threats of SCC and external corrosion. As noted previously periodic integrity assessment is needed to mitigate both of these phenomena. The operator could choose to mitigate SCC via periodic hydrostatic testing, ILI crack detection tool runs, or possibly by means of SCCDA.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of SCC and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

The Low-Stress Natural Gas Pipeline Case

If one assumes that a 50-mile-long low-stress natural gas pipeline is comprised of 16-inch-OD, 0.250-inch-wall, X52 HF-ERW pipe operated at an MAOP of 485 psig (<30% of SMYS), then except for the pipe size and operating pressure differences, the process for making a repair/replace decision is identical to that presented in Base Case Example No. 3. Instead of being directed to Figure C2 (LEGACY PIPE) and Figure C3 (LF-ERW) for legacy pipe, however, the operator is directed to Figure C8 (MODERN PIPE) and Figure C9 (HF-ERW).

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threat of external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

A Pipeline Comprised of Seamless Pipe

The Hazardous Liquid Pipeline Case

Consider a 200-mile-long refined products pipeline comprised of 12.75-inch-OD, 0.312-inch-wall, API 5LX42 seamless line pipe. The pipeline was installed in 1955. It was coated over-the-ditch with a coal tar enamel coating. An impressed-current cathodic protection system was installed and activated within the first year of operation of the pipeline. The pipeline is operated at an MOP of 1440 psig corresponding to a hoop stress level of 70% of SMYS. It can accommodate all types of ILI. It is not exposed to internal corrosion because it transports only refined products.

The pipeline was subjected to a pre-service hydrostatic test to a minimum pressure level of 1600 psig which is 1.11 times the MOP and corresponds to a hoop stress level of 78% of SMYS. In 1979, the operator subjected the pipeline to another hydrostatic test to a minimum pressure

level of 1800 psig which is 1.25 times the MOP and corresponds to a hoop stress level of 87.6% of SMYS. The pipeline has exhibited no leaks or ruptures from any time-dependent cause.

In 2002, as part of the operator's integrity management plan, the pipeline was subjected to an integrity assessment for corrosion-caused metal loss using an MFL tool. Areas of external metal loss were found, and those judged severe enough to be integrity-threatening were excavated and examined. These areas were repaired if required and recoated. Some internal metal loss anomalies were found as well. However, these few anomalies were judged to be typical seamless pipe manufacturing anomalies that can be expected to remain stable. The reason they were believed to be manufacturing anomalies and not internal corrosion-caused metal loss is that they tended to be isolated and were oriented at random clock positions. These will be monitored in subsequent ILI tool runs.

Subsequent ILI tool runs to assess for corrosion-caused metal loss were carried out in 2007 and 2012. Additional external metal loss was found each time and repaired as required. The areas of internal metal loss seen on the first inspection in 2002 were again identified in 2007 and 2012. Significantly, no new areas of internal metal loss were identified, and as far as could be determined, the ones identified in 2002 did not appear to have grown. The assumption that these are non-threatened manufacturing defects appears justified.

Although no evidence of SCC has been discovered on the pipeline, the operator decided that the threat should be addressed by means of an SCCDA program with periodic examinations of selected sites.

Concerning the potential threat of failure from PCIF, although no fatigue failures have occurred, the analysis of pressure cycles on the pipeline carried out in 2012 shows that the predicted minimum time to failure after the 1979 hydrostatic test is 24 years (forecasting a potential failure in 2003). The fact that no such failure from PCIF has occurred probably means one or a combination of three things, 1) the worst-case defect that could have survived the 1979 test did not exist or was not located in the worst-case location, 2) the pressure cycles have not always been as aggressive as the spectrum used for the analysis, or 3) the crack growth rate constants taken from API RP 579 are more conservative than the actual crack growth rate constants. To address the unknown risk of failure from PCIF, the operator should consider either a hydrostatic retest or an ILI crack-tool inspection as soon as possible and should also plan to repeat the test or inspection at an interval of 12 years on the basis of the fatigue analysis showing 24 years as the minimum time to failure. Assume that the operator elects to carry out an ILI crack-tool inspection in 2015. The inspection may or may not result in the finding of cracks that may have been extended by fatigue. Whatever the outcome, assume that the operator plans to repeat the inspection every 12 years based on the predictions of the 2012 fatigue analysis.

To make a repair/replace decision regarding this pipeline, the operator can utilize the flowcharts of Appendix C. Figure C1 (Flowchart START), steers the operator to Figure C8 (Flowchart MODERN PIPE), which in turn steers the operator to Figure C11 (Flowchart SEAMLESS). Flowchart SEAMLESS addresses the issues related to the fact that this pipeline is comprised of seamless pipe. Flowchart SEAMLESS is shown below as Figure 29.

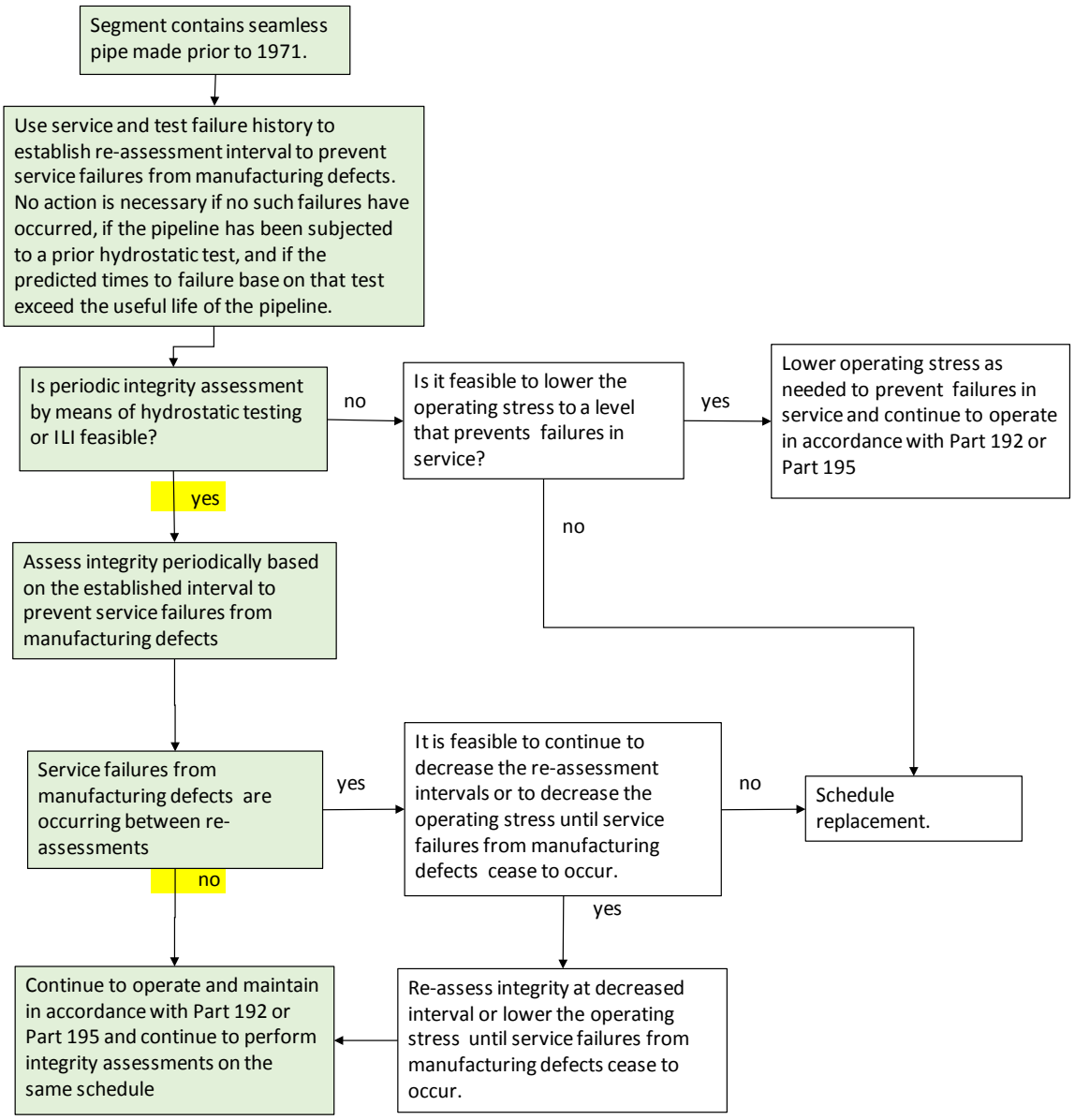


Figure 29. Flowchart for Evaluating a Repair/Replace Decision for Seamless Pipe in a Hazardous Liquid Pipeline

The operator must also review Figure C12 (EC) and Figure C14 (SCC). As suggested in several of the previous examples periodic ILI tool runs to monitor for metal loss and either periodic

hydrostatic testing, periodic ILI crack-detection tool runs, or SCCDA are needed for mitigating SCC.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, SCC, and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

The High-Stress Natural Gas Pipeline Case

If one assumes that a high-stress natural gas pipeline is comprised of the same seamless pipe described above for a hazardous liquid pipeline, the required mitigation would be the same for SCC and external corrosion. The likelihood is the pressure cycle spectrum of the gas pipeline would not be sufficiently aggressive to cause PCIF to be a threat within the useful life of the pipeline.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threats of PCIF, SCC, and external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

The Low-Stress Natural Gas Pipeline Case

If one assumes that a low-stress natural gas pipeline is comprised of the same seamless pipe described above for a hazardous liquid pipeline, the required mitigation would be the same for external corrosion. The likelihood is the pressure cycle spectrum of the gas pipeline would not be sufficiently aggressive to cause PCIF to be a threat within the useful life of the pipeline. The operating stress level of the low-stress natural gas pipeline is below the threshold stress for SCC. Since the low stress pipeline cannot accommodate ILI tools because of the low pressure level, ECDA will have to be used to mitigate the threat from external corrosion.

The operator must assure that safety and pipeline integrity are maintained when comparing the cost to continue mitigating the threat of external corrosion with the cost of replacement of the pipeline in order to decide whether to repair or replace.

A Pipeline Susceptible to Internal Corrosion

Any pipeline whether it is a hazardous liquid pipeline, a high-stress natural gas pipeline, or a low-stress natural gas pipeline may be exposed to internal corrosion[30]. For a pipeline that is in

[30] In compiling these responses to an internal corrosion threat, only onshore pipelines were considered. It is entirely possible that the internal corrosion threat to an offshore pipeline could require analysis and solutions beyond the scope of these guidelines. It is suggested that those interested in repair/replace decisions for offshore pipelines consult the numerous technical papers dealing with the operation and maintenance of offshore pipelines.

dedicated sour service with water present all of the time, the operator may have in place an internal corrosion mitigation plan consisting of running cleaning pigs and injecting inhibitors and/or biocides, and a monitoring plan that may involve periodic ILI tool runs to detect metal loss. In the case of a pipeline that is normally not in sour service, sour gases or liquids may enter the pipeline occasionally from upset conditions at gas treatment facilities. In such a case the operator may not have in place a mitigation and monitoring plan, but it may be prudent to assess the integrity of the pipeline from the standpoint of internal corrosion. The response required to prevent leaks and ruptures from internal corrosion can be carried out as portrayed in Appendix C. The START flowchart (Figure C1) directs the operator to either the LEGACY PIPE flowchart (Figure C2) or the MODERN PIPE flowchart (Figure C8) either of which, in turn, directs the operator to the IC flowchart. Flowchart IC is shown below as Figure 30.

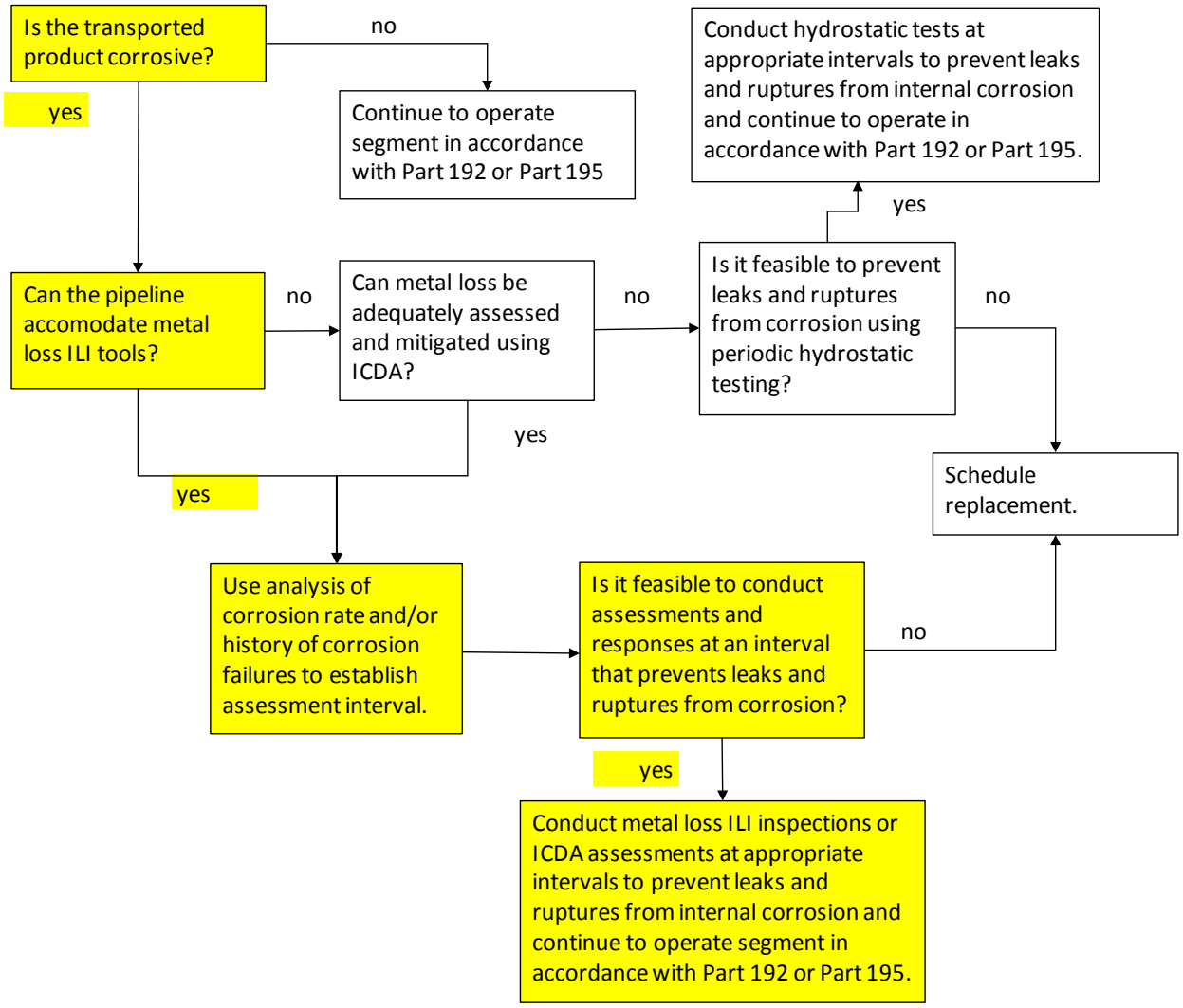


Figure 30. Preventing Leaks and Ruptures from Internal Corrosion

The process begins with the question "Is the transported product corrosive?". The answer is yes whether the pipeline is in dedicated sour service or is exposed on occasion to sour conditions. If the pipeline can accommodate ILI metal loss tools, periodic assessments with an ILI tool should be made using knowledge about the likely rate of metal loss. That case is represented by the highlighted cells in Figure 30. If the pipeline cannot accommodate the appropriate ILI tool, the operator can utilize ICDA to periodically monitor for internal metal loss. Alternatively, the operator could assess the integrity of the pipeline via hydrostatic testing, though as discussed previously, this approach is an inefficient method to assess integrity from the standpoint of corrosion. If sour service is known to exist or to have existed and no form of assessment for internal metal loss can be carried out, the operator should consider replacing the pipeline. Alternatively it may be possible to increase the flow velocity to a level that is above water entrainment velocity. The operator might also decide to replace a pipeline if the cost of mitigating and/or responding to internal corrosion and possibly other threats as well becomes too high relative to the cost of replacement. The replacement pipeline could be constructed of a material more resistant to sour conditions, and the operator can plan for appropriate monitoring and inspection in the design phase.

A Pipeline Containing Legacy Repairs

In the past, defects in pipelines were often repaired by means of puddle welds, patches, or half soles. Puddle-welding in this context does not include the class of deposited-weld-metal repairs that follow specific, proven procedures. The old-style puddle weld was usually made in one of two circumstances. In one circumstance, puddle welding was carried out on in-service pipelines with little or no procedural documentation. These welds frequently have been accompanied by crack formation and, in some cases, eventual leakage. In the second circumstance, they were used to fill pits in corroded pipe which had been removed from service for re-installation in the same or a different pipeline. In the latter circumstance, the puddle welds are usually of acceptable quality and have not been known to be a frequent source of leaks.

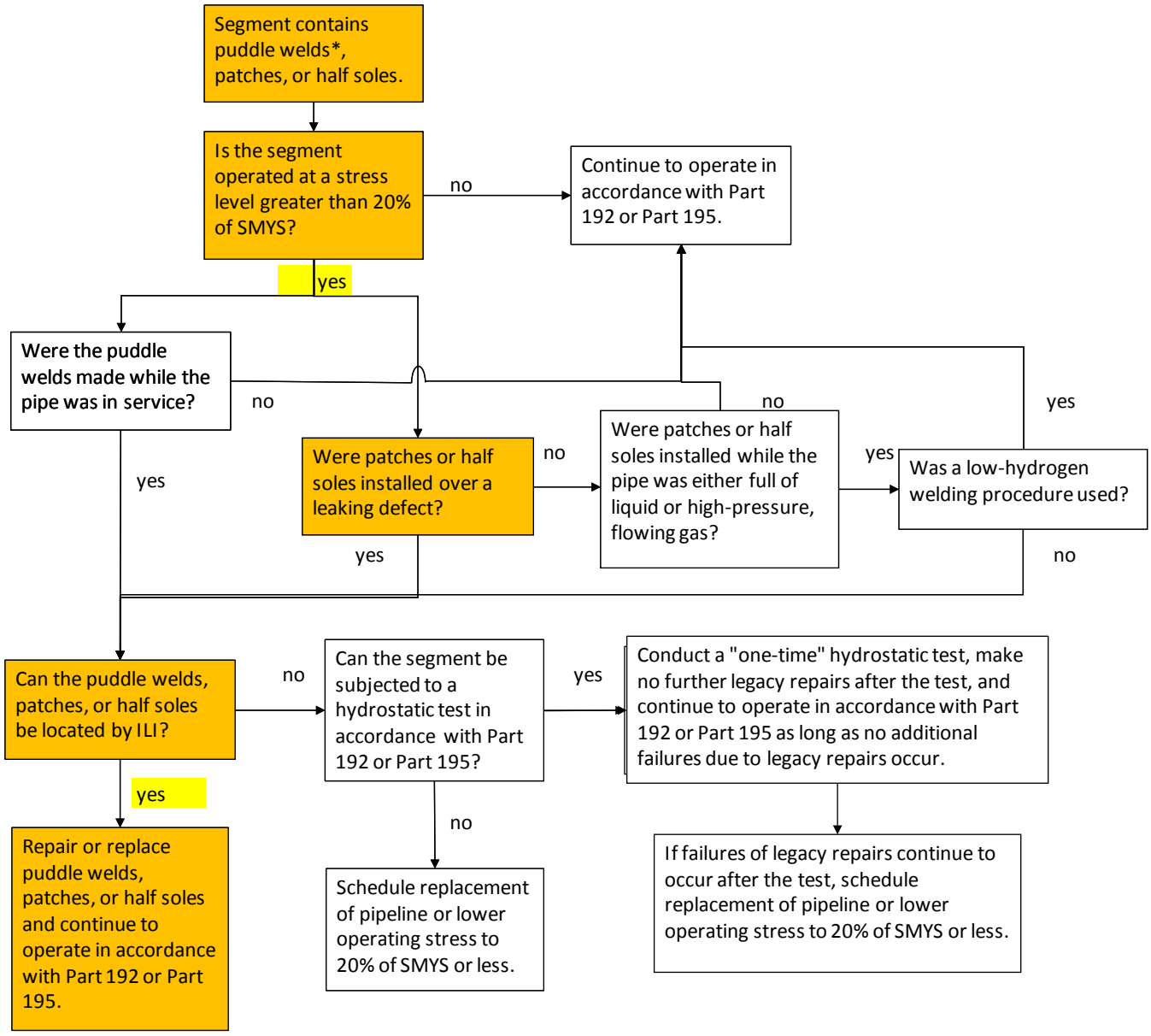
Patch repairs generally consisted of rectangular, curved pipe segments usually no greater in size than 6-inches in either direction that were fillet welded over a defect. The longitudinal welds are acted upon by hoop stress, and thus they can serve as fatigue crack initiators particularly if under-bead cracks formed from too-rapid cooling and the use of non-low-hydrogen consumables. In cases where patches were installed on liquid-filled pipelines or pipelines containing high-pressure flowing gas, the risk of under-bead crack formation was especially high[31]. The longitudinal fillet welds on patches have been shown to be more

[31] The same threat could be associated with Type B full-encirclement sleeves where the ends of the sleeves are fillet welded to the pipe. If leaks or ruptures have occurred in a given pipeline in conjunction with Type B sleeves, the operator should consider repairing or removing any sleeves made with the same procedures used on sleeves which have caused leaks or ruptures in the past.

vulnerable to failure when installed over leaks where the patches were exposed to operating pressure fluctuations.

Half soles are nothing more than a large patch, usually made from half of a full-encirclement sleeve. Half soles have all of the undesirable properties of patches and are now barred from use in pipelines operated in conformance with ASME B31.4 and ASME B31.8.

When considering whether to replace such legacy repairs, a pipeline operator may use the flowcharts of Appendix C. The START flowchart (Figure C1) directs the operator to either the LEGACY PIPE flowchart (Figure C2) or the MODERN PIPE flowchart (Figure C8) which, in turn, directs the operator to the LEGACY REPAIRS flowchart (Figure C7). Figure C7 is reproduced as Figure 31 below.



*Puddle welding refers to welds made with an unknown welding proceddure to repair pits or other defects. Deposited weld metal repairs made according to a documented and proven procedure are a legitimate repair method and do not fall under this definition of puddle welding.

Figure 31. Process for Responding to Legacy Repairs

Figure 31 illustrates for any pipeline that can accommodate a MFL or CMFL tool, the procedure one can follow to determine how to respond to legacy repairs. First, legacy repairs are considered to be of concern if the pipeline is operated at a stress level in excess of 20% of SMYS. In the particular pipeline considered in Figure 31, there are no puddle welds, only patches and half soles. Patches or half soles installed over leaks are slated for mitigative action which in this case consists of finding the patches or half soles by means of ILI and repairing or removing them. Note that it may or may not be possible to tell whether a patch or half sole

had been installed over a leak. Also note that any puddle welds that had been made while the pipeline was in service would be slated for mitigative action as well.

If the legacy repairs are slated for repair or removal and ILI cannot be used to locate them, the operator has the option of performing a "one-time" pressure test[32] in conformance with the federal regulations. If the pipeline cannot be pressure-tested or if failures of patches or half soles continue to occur after the one-time test, replacement of the whole pipeline or a reduction to an operating stress level of 20% of SMYS or less is recommended. .

If there are patches or half soles that have not been installed over leaks and were installed while the pipeline was full of liquid or high-pressure, flowing gas using a low-hydrogen welding procedure, there is no need to remove them. Similarly, if the patches or half soles had been installed on an empty pipeline, there is no need to remove them. However, patches and half soles installed while the pipeline was full of liquid or high-pressure, flowing gas with a non-low-hydrogen welding procedure should be slated for removal.

If the example pipeline contained puddle welds instead of or in addition to patches and half soles, no action is required if the puddle welds were fabricated with the pipe out of service. On the other hand, puddle welds fabricated while the pipeline contained a liquid product or high-pressure, flowing gas should be located by ILI is feasible and repaired or the affected pipe should be replaced. Alternatively, if locating the puddle welds by means of ILI is not feasible, the pipeline should be subjected to a one-time hydrostatic test to locate weak spots associated with the puddle welds.

As in the cases of other threats discussed previously, where legacy repairs are an issue (in conjunction with other needs for threat mitigation), the operator is likely to choose between repair and replacement based on comparing the costs of the two options, taking into account the cost of maintaining safety and integrity of the pre-regulation pipeline.

A Pipeline Susceptible to HSC in Pipe Body Hardspots

Suppose that the natural gas pipeline described in Table 5 had sustained a failure from a pipe body hard spot. Such hard spots have been detected in A.O. Smith flash-welded pipe made in the period between 1947 and 1960. Assume that every other aspect of this case is the same as described in Base Case 2. The only difference to be considered is the threat of HSC in pipe

[32] The idea of a one-time test to address patches, half-soles, or puddle welds is to rid the pipeline of possible weak spots associated with these types of repairs. If leakage from such repairs continues to occur, the operator should consider replacing the pipeline. Repeated hydrostatic testing is likely to make leakage of such repairs worse because they are particularly susceptible to pressure reversals. One of the authors discovered this the hard way by trying to retest pipe specimens with multiple defects using patches and puddle welds to repair leaks rather than cut them out.

body hard spots. The factors that would influence a repair/replace decision for this pipeline would be the same as those in Base Case 2 except that operator in this case needs to consider the threat of failure from HSC as well. That can be done using Appendix C Figure C15 HSC which is reproduced below as Figure 32 for this particular pipeline.

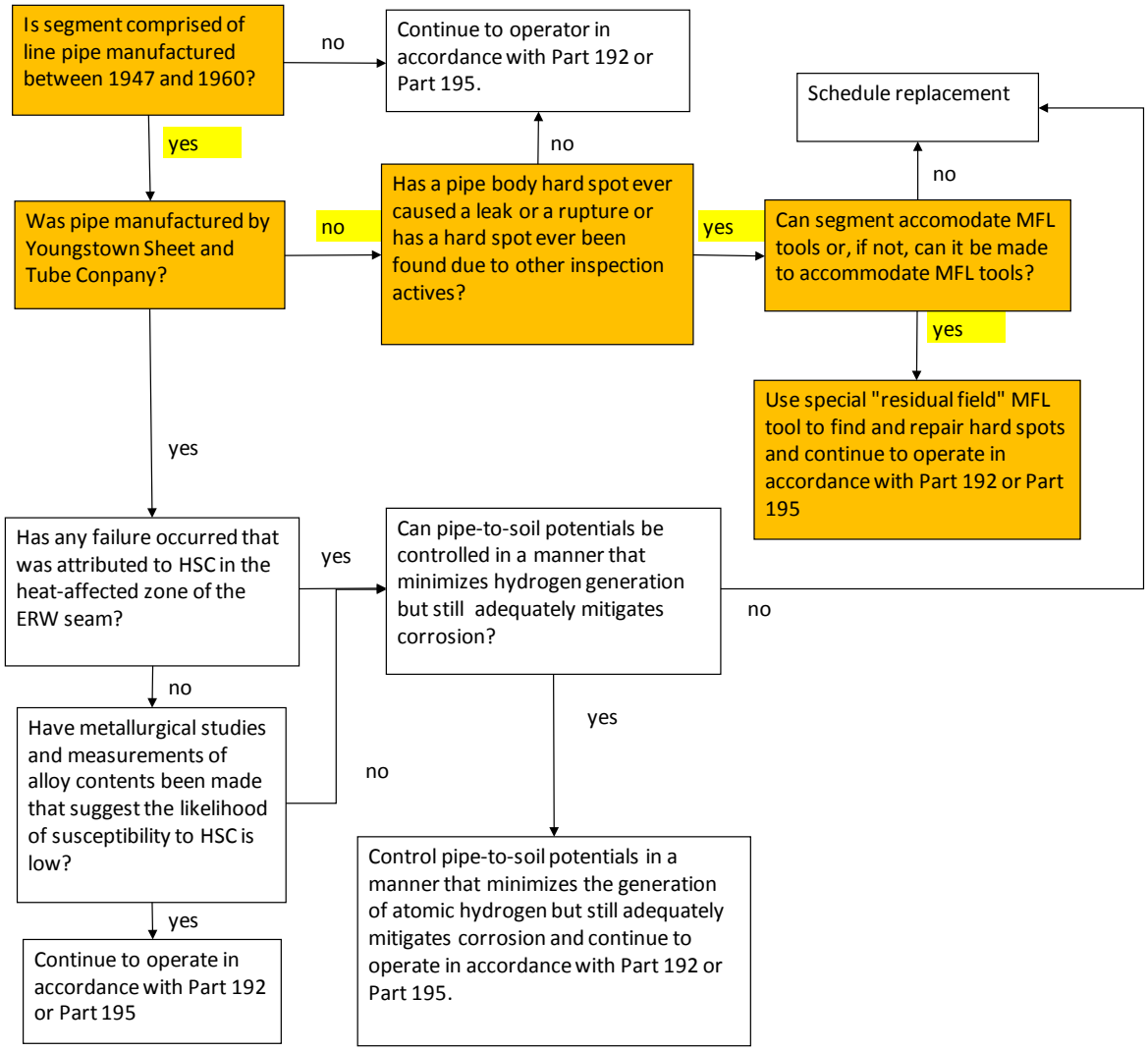


Figure 32. Process for Responding to an HSC Threat in a Pipe Body Hard Spot

As can be seen in Figure 32, the fact that a failure of a pipe body hard spot has occurred means that the operator must address the threat of HSC. Fortunately, the pipeline can accommodate the type of MFL tool that can be used to locate pipe body hard spots. The operator should use such a tool to locate the hard spots. Every hard spot should be excavated and examined. Local hardness measurements can be made to verify the hardness levels. In addition, hard spots are sometimes visible because the hard region has less curvature than the unaffected pipe due to its higher yield strength. The pipe containing the hard spots may be removed and replaced with sound pipe. Alternatively, full-encirclement steel sleeves (not composite wraps) should be

installed over the hard spots to shield them from cathodic protection. This prevents atomic hydrogen from being generated at the hard surface. This can be a one-time repair program because it will eliminate the threat. Re-assessment for HSC is not necessary if all of the hard spots are removed or repaired. In this case the hard spot problem does not lead to pipeline replacement. However, if the operator is unable to run the appropriate tool to find the hard spots and eliminate the threat, replacement of the pipeline must be considered.

A Pipeline Susceptible to HSC in the HAZ of its DC-ERW Seam

Suppose that the hazardous pipeline described in Table 4 was comprised of 1953-vintage DC-ERW pipe manufactured by Youngstown Sheet and Tube Company. Pieces of pipe made by this manufacturer in the period between 1947 and 1960 have been known to have heat-affected-zone hardnesses of Rockwell C35 or higher, making them susceptible to HSC. Assume that every other aspect of this case is the same as described in Base Case 1. The only difference to be considered is the threat of HSC in heat-affected zones adjacent to the ERW seams. The factors that would influence a repair/replace decision for this pipeline would be the same as those in Base Case 1 except that the operator in this case needs to consider the threat of failure from HSC as well. That can be done using Appendix C Figure C15 HSC which is reproduced below as Figure 33 for this particular pipeline.

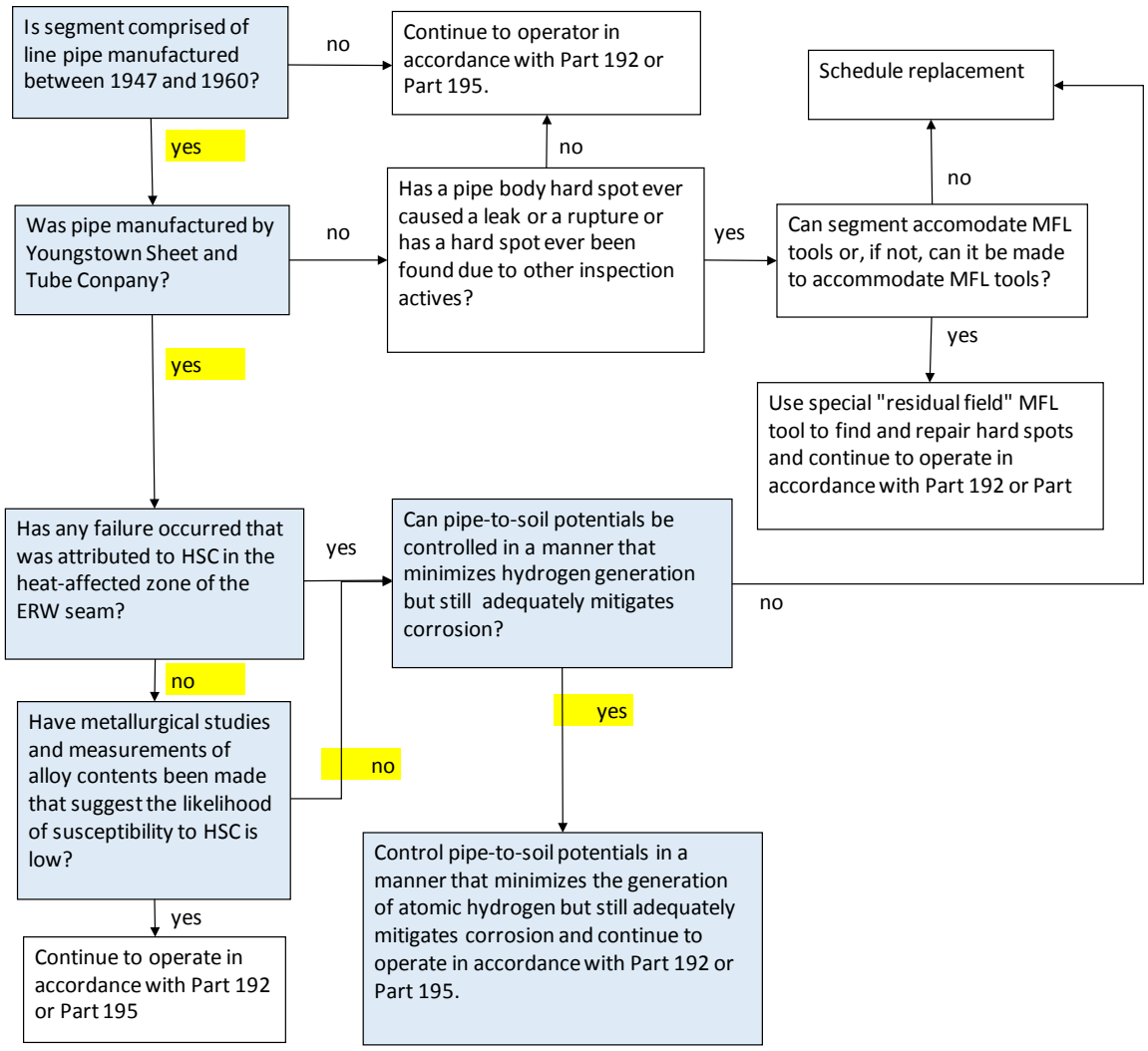


Figure 33. Process for Responding to an HSC Threat in a Hard HAZ

Because the pipe was manufactured by Youngstown Sheet and Tube Company during the critical time period when hard heat-affected zones could have been produced, the operator must take mitigative action even if no failure from a hard heat-affected-zone crack has occurred. One way to do this is to examine records of chemical analyses of the heats of steel (if available) to ascertain whether or not the carbon and manganese contents were sufficiently high to make the material easily hardenable. Alternatively, the operator may have the opportunity to remove a significant number of metallurgical samples to verify that high hardness levels do not exist. If no failure from HSC in a hard heat-affected zone has occurred, and the material does not seem to be readily hardenable, the operator may be able to avoid any further remedial action. If the non-susceptibility to HSC cannot be established with a high level of confidence, then further remedial action is needed.

If a failure from HSC has occurred, or if the non-susceptibility of the pipe cannot be established, the operator should modify the cathodic protection system by adding ground beds if necessary to control the range of pipe-to-soil potentials, in order to achieve adequate cathodic protection without having excessively high pipe-to-soil potential levels that could lead to aggressive hydrogen charging of the pipe in areas of disbonded coating. Alternately, the operator could consider using a less conservative cathodic protection criterion like the 100 mv polarization criteria which uses less polarization than the -0.85-volt criterion. This will help reduce the potential level for hydrogen charging. If neither of these prove effective at mitigating the HSC threat, the operator should consider replacing the pipeline.

Flowcharts for Gas Distribution Systems

The flowcharts for making repair/replace decisions for gas distribution systems are presented in Appendix C, Figures C16 through C27. These figures cover the three types of pipe materials used in most gas distribution systems: steel, plastic, and cast iron.

System Attributes, Operational Data, and History

The system attributes that are essential for making repair/replace decisions for steel, plastic, or cast iron pipe systems were presented previously in Tables 6-8 for the "base case" distribution systems. The various operational data, and historical operating experience that bear on repair/replace decision-making were discussed previously. The decision-making criteria are demonstrated below by means of examples.

Base Case Example No. 4: A Steel Gas Distribution Main

Consider the steel natural gas distribution main described in Table 6. It is comprised of 4.5-inch-OD, 0.188-inch-wall, Grade A pipe manufactured and installed in 1942 with a low-frequency electric resistance welded seam. Each piece of pipe was hydrostatically tested by the manufacturer to a stress level of 60% of SMYS for a total time of 10 seconds. The distribution main is 10 miles long and is operated at a maximum hoop stress level of 5.98% of SMYS. The MAOP of the pipeline is 150 psig. The main was installed uncoated with no cathodic protection.

The operator has records documenting all aspects of the pipeline's design, construction, and operation since 1942. The leak history indicates that leaks from external corrosion have been generally increasing since 1953. The main also contains 50 drips and three dead-legs that have the potential to pose issues with internal corrosion, even though the line normally carries dry natural gas with no sour components, and no leaks due to this threat have occurred.

There is no record of a post construction pressure test for this main. Since the distribution main is directly connected to the end users through hundreds of service connections, service

cannot be interrupted. The main cannot be taken out of service to perform a pressure test, and it cannot accommodate an in-line inspection tool.

To determine whether or not this main should be replaced, the operator can go through the process described below starting with Flowchart START (for steel gas distribution main) (Figure C16 of Appendix C). Flowchart START (for steel gas distribution main) is repeated as Figure 34 below as adapted to this particular pipeline.

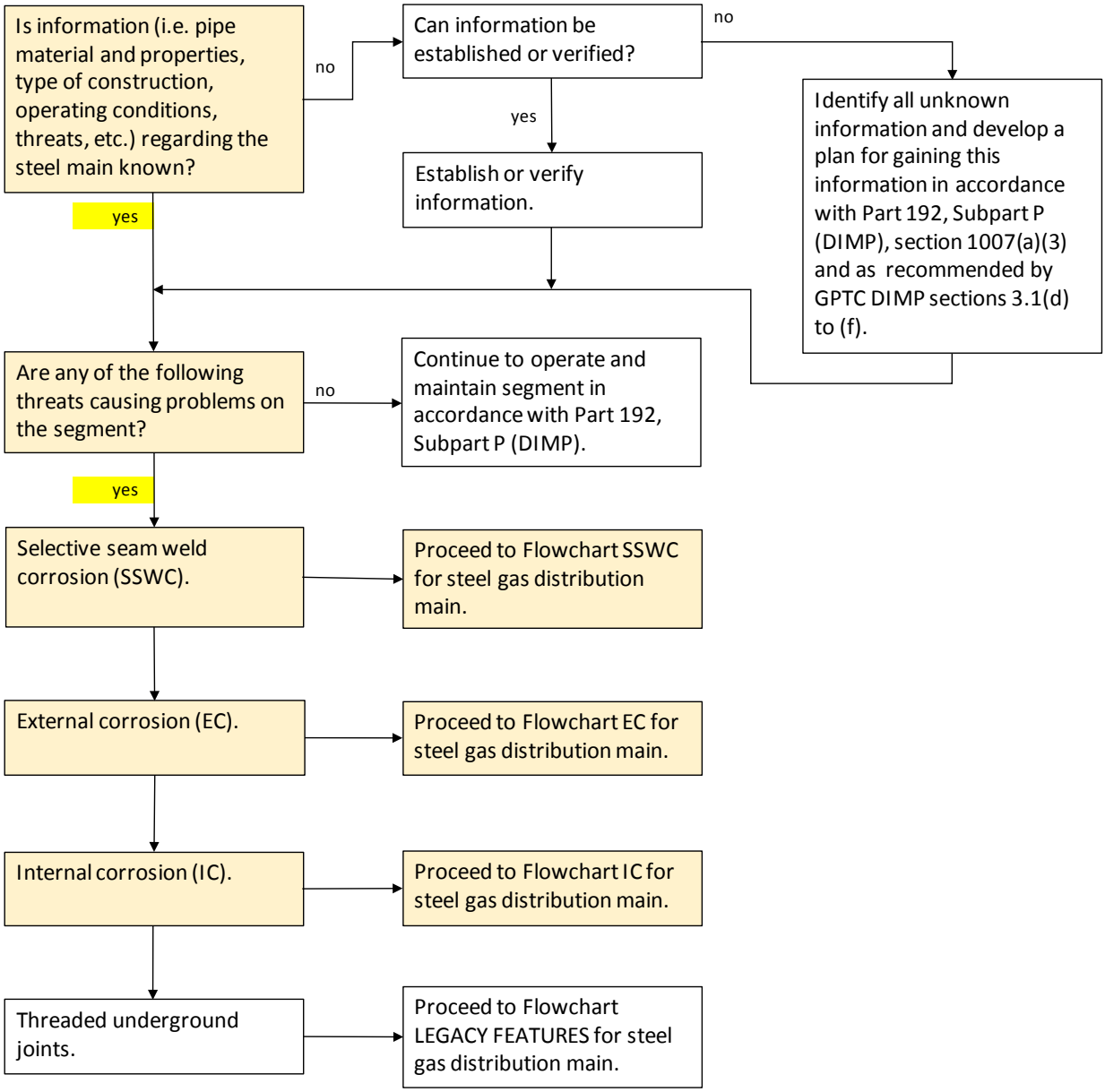


Figure 34. Start of Process to Decide Whether to Repair or Replace the Base Case Steel Gas Distribution Main

The information regarding this main is known. If some or all of the vital information such as diameter, wall thickness, seam type, or specified minimum yield strength were not known, the operator would have to identify all unknown information and develop a plan for gaining this information in accordance with Part 192, Subpart P (DIMP), section 1007(a)(3) and as recommended by GPTC DIMP[33] sections 3.1(d) to (f).

The segment may be susceptible to selective seam weld corrosion (SSWC), so the next step is to proceed to Figure 35 which is Flowchart SSWC (for steel gas distribution main) (Figure C17 of Appendix C). Note that types of pipe known to be susceptible to SSWC are Electric Flash Welded, Low-Frequency Electric Resistance Welded (LF-ERW), and High-Frequency Electric Resistance Welded (HF-ERW) pipe manufactured prior to 1980, or where the toughness of the seam region was low or not specified.

Any steel distribution main may be susceptible to degradation from external or internal corrosion; therefore the operator should assess the segment for these threats accordingly. So, after assessing the segment for a SSWC threat, the operator of the pipeline must pursue the process of making a repair/replace decision via Flowcharts EC (for steel gas distribution main) and IC (for steel gas distribution main) shown in Figure 36 (Figure C18 of Appendix C) and Figure 37 (Figure C19 of Appendix C), respectively.

This base case pipeline contains no threaded underground joints or other obsolete features, so the operator of this pipeline need not consider the threats represented in Flowchart LEGACY FEATURES (for steel gas distribution main) (Figure C20 of Appendix C).

[33] GPTC DIMP guidelines are promulgated and maintained by the Gas Piping Technology Committee of the American Gas Association.

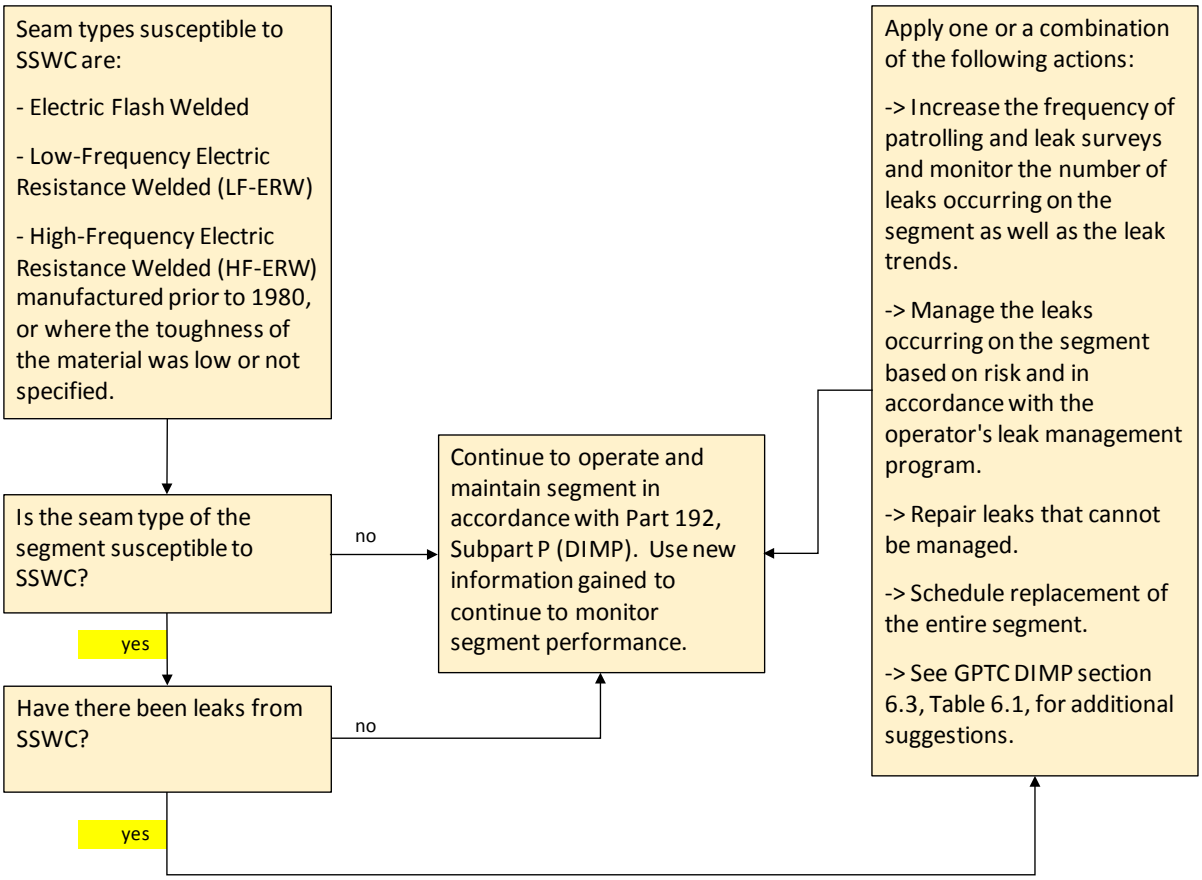


Figure 35. Feasibility of Preventing in-Service Failures from SSWC (for steel gas distribution main)

According to Figure 35, since the main is comprised of LF-ERW pipe, which is susceptible to SSWC, the operator should review the history of in-service failures to determine whether any of the leaks that occurred on the line were due to SSWC. In this particular case, some of the leaks experienced were found to have occurred in the longitudinal seam of the pipe and thus were attributed to SSWC. The flowchart suggests that the operator take some type of additional or accelerated (A/A) action such as those suggested in GPTC DIMP Table 6.1 in order to appropriately manage the threat and minimize the risk. The A/A actions in this table are not meant to be restrictive, but instead are meant to serve as suggestions. The operator is free to take any action that helps reduce the risk of the SSWC threat to the segment. After an action is applied, the operator should use any new knowledge it gained through this process to monitor the performance of the main and operate and maintain the segment in accordance with Part 192, Subpart P and the operator's Distribution Integrity Management Program (DIMP). After the threat of in-service failures attributed to SSWC has been addressed, the operator should refer back to Flowchart START (for steel gas distribution main) and assess the other threats to which the main is susceptible.

Returning to Flowchart START (for steel gas distribution main), the operator of this main should assess the next applicable threat, which in this case happens to be external corrosion. Flowchart EC, shown in Figure 36, should be used to analyze this threat.

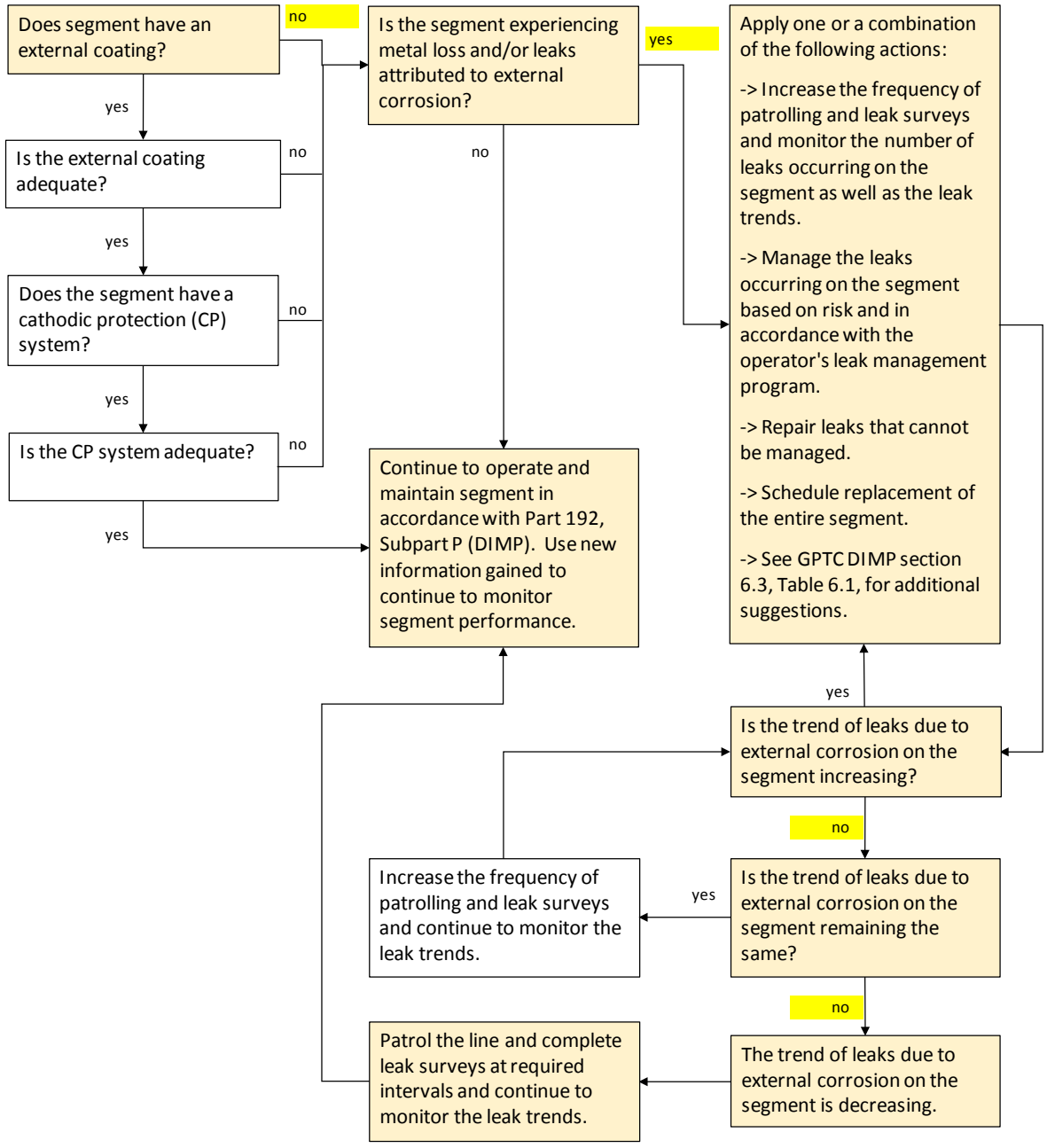


Figure 36. Feasibility of Preventing in-Service Failures from External Corrosion (for steel gas distribution main)

According to Figure 36, this main does not have an external coating and the operator has confirmed it is experiencing leaks attributed to external corrosion. The operator should take an A/A action such as installing sacrificial anodes[34], increasing the frequency of its patrolling and leak surveys, while also managing the leaks based on risk and in accordance with its leak management program. After the leaks posing the most risk are addressed, it is noted that the leak trend along the segment is decreasing. The operator should continue to patrol the line and complete leak surveys at required intervals, and should continue to operate and maintain the segment in accordance with the DIMP regulations. Any new information gained throughout the DIMP process such as updated leak trends should be used to continue to monitor the segment's performance. Had the trend of external corrosion leaks in this particular case remained the same or continued to increase, the operator would need to reassess the situation and take additional action to manage the leaks occurring along the line. Continually increasing leak trends despite A/A actions and mitigation efforts would lead the operator to determine that replacement of the main might be the best option due to the corrosion issue being too severe to feasibly mitigate.

Again returning to Flowchart START (for steel gas distribution main), the operator of this main should assess the last applicable threat, which is internal corrosion. Flowchart IC (for steel gas distribution main), shown in Figure 37, should be used to analyze this threat.

[34] When sacrificial anodes are installed, it is important to record their locations and desirable to equip them with a shut-off mechanism to facilitate on/off pipe-to-soil potential measurements.

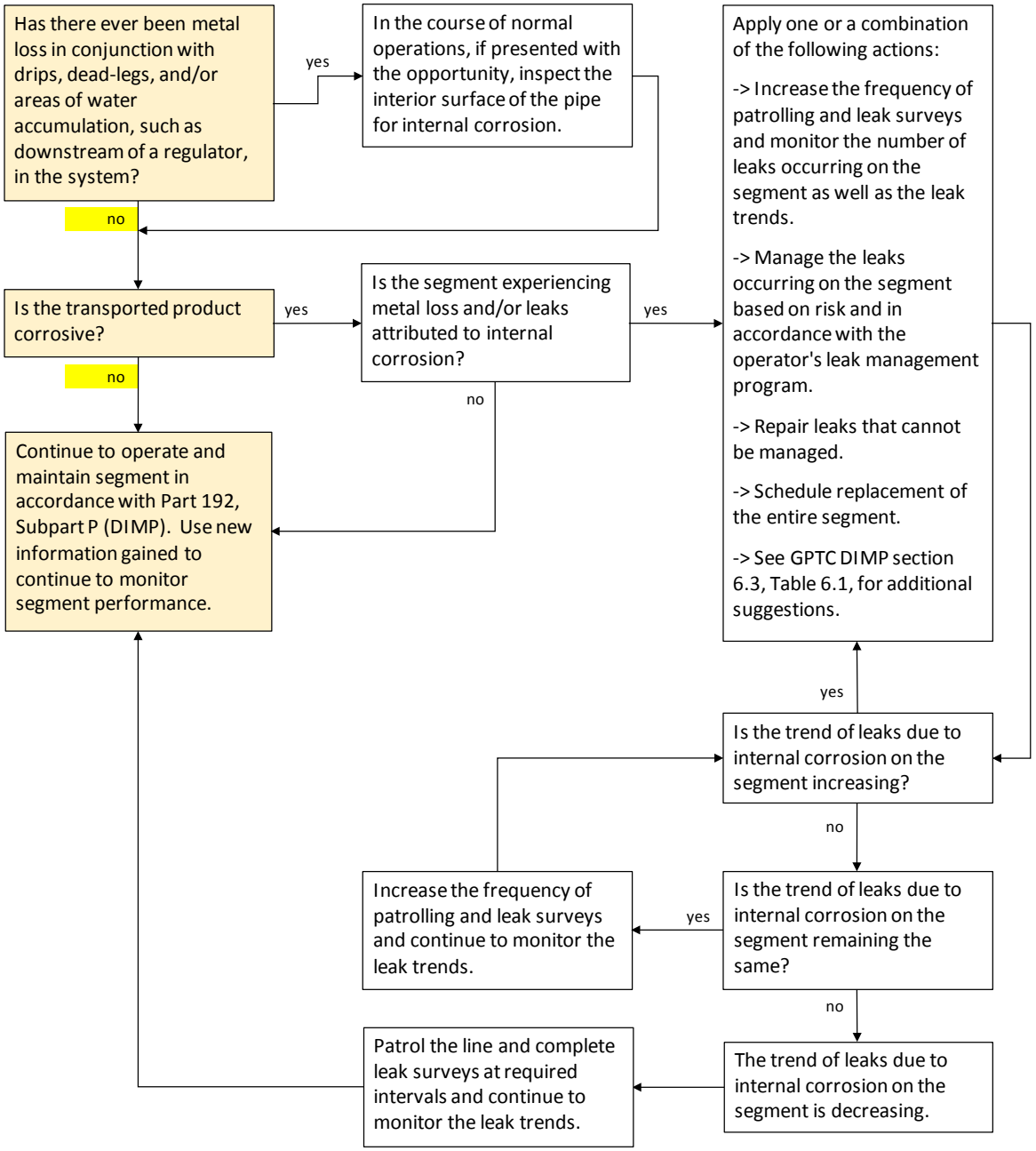


Figure 37. Feasibility of Preventing in-Service Failures from Internal Corrosion (for steel gas distribution main)

According to Figure 37, while this main has both drips and dead-legs that exist in the system, the operator has confirmed that no metal loss in conjunction with these features has occurred. During the course of normal operations, if presented with the opportunity such as during a repair, the operator should inspect the interior surface of the main for signs of internal corrosion and/or water accumulation. Water should be drained from the system, if found, and the segment should be cleaned out, if possible. If pitting is discovered, the severity needs to be assessed, and if leakage is imminent, it should be managed in an acceptable manner. Since the

product transported in this main is not corrosive and none of the leaks occurring along the main can be attributed to internal corrosion, the operator can continue to operate and maintain the segment in accordance with the DIMP regulations. Had the transported product been corrosive and the main been experiencing leaks attributed to internal corrosion, the operator would need to take an A/A action to manage the leaks along the line as well as monitor the leak trends. The operator's capability of addressing internal corrosion issues as well as the costs associated would determine whether the internal corrosion issues could be managed or if replacement would be necessary.

The above analysis indicates that the threats to the integrity of this main are being mitigated through the applied A/A actions being taken by the operator. Judging whether the operator should continue to apply these A/A actions and continue to operate the main going forward versus replacing it can be decided based upon the cost to maintain the integrity of the existing pipeline versus the cost to replace it. The cost to maintain and reassess the main to a level required for preventing in-service leaks depends on the costs of the various A/A actions discussed above. If these continuing costs are acceptable to the operator, then replacement is not necessary.

Base Case Example No. 5: A Plastic Gas Distribution System

Consider the plastic natural gas distribution system piping described in Table 7. It is comprised of 2.375-inch-OD, 0.216-inch-wall, polyethylene (PE) pipe manufactured by Century Utilities Products, Inc. and installed in 1976 with butt heat-fusion joints. Each piece of pipe had a hydrostatic design basis (HDB) at 73°F of 1250 psi. The distribution system consists of 15 miles of the aforementioned piping. The MAOP of the pipeline is 60 psig.

The operator has records documenting all aspects of the pipeline's design, construction, and operation since 1976. The leak history indicates that leaks due to slow crack growth have been increasing since 1989. The leak history also mentions a number of leaks experienced at joint or tap connections in 1979, shortly after the system was put into service, however after repairs were made no further failures of this type have been experienced.

It is assumed that the main was tested to 1.5 times the MAOP. Since the distribution system piping is directly connected to the end users through hundreds of service connections, service cannot be interrupted. The main cannot be taken out of service to perform a pressure test, and it cannot accommodate an in-line inspection tool.

To determine whether or not this piping should be replaced, the operator can go through the process described below starting with Flowchart START (for plastic gas distribution main) (Figure C21 of Appendix C). Flowchart START (for plastic gas distribution main) is repeated as Figure 38 below as adapted to this particular pipeline.

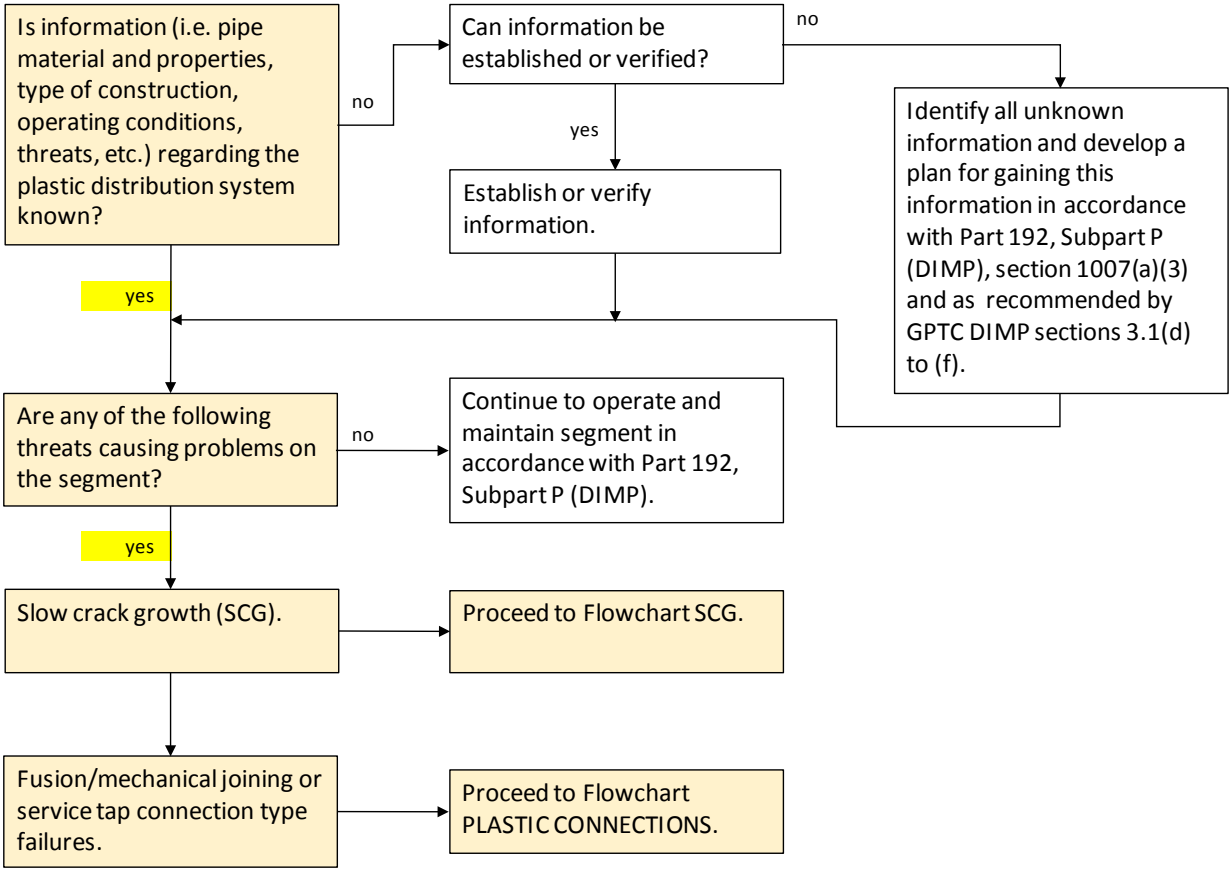


Figure 38. Start of Process to Decide Whether to Repair or Replace the Base Case involving a Plastic Distribution System

The essential attributes of this main are known. If some or all of the vital information such as diameter, wall thickness, seam type, or specified minimum yield strength were not known, the operator would have to identify all unknown information and develop a plan for gaining this information in accordance with Part 192, Subpart P (DIMP), section 1007(a)(3) and as recommended by GPTC DIMP sections 3.1(d) to (f).

The segment has been experiencing leaks due to slow crack growth (SCG). So, the next step is to proceed to Figure 39 which is Flowchart SCG (Figure C22 of Appendix C).

Any plastic distribution system may be susceptible to joining or tap connection failures such as a bad fusion joint or a bad bolt-on type of tee; therefore, after assessing the segment for an SCG threat, the operator should proceed to Flowchart PLASTIC CONNECTIONS (Figure C23 of Appendix C), shown in Figure 40, to assess the segment for a joining or tap connection type threat accordingly.

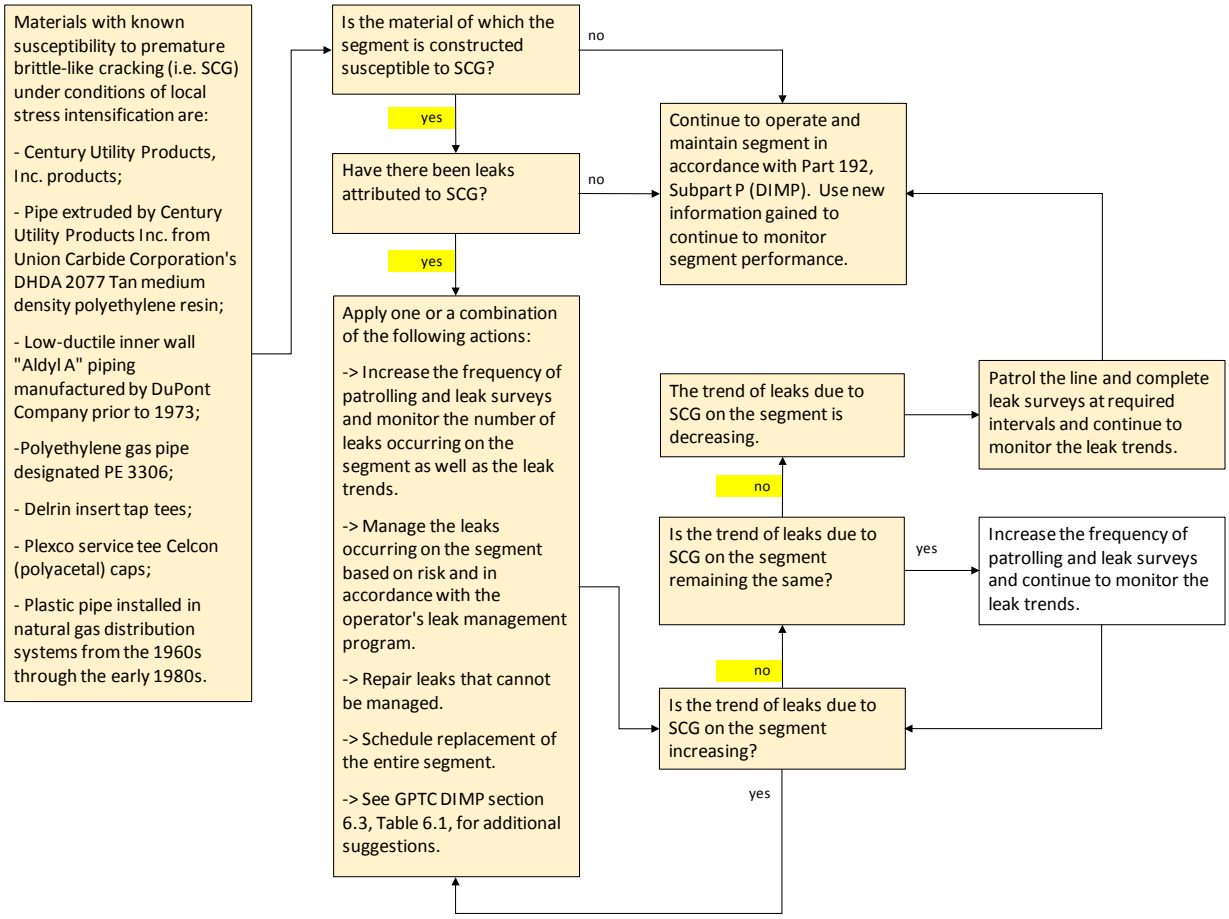


Figure 39. Feasibility of Preventing in-Service Failures from Slow Crack Growth

According to Figure 39, the operator should first determine whether the distribution system was constructed of a pipe material known to be susceptible to premature brittle-like cracking (i.e. SCG) under conditions of local stress intensification. An increase in the occurrence of leaks will typically be the first indication of a SCG problem, and this condition can substantially reduce the service life of polyethylene piping systems. In this particular case, the operator discovered that the system piping was manufactured by Century Utility Products, Inc. which has been identified in a PHMSA advisory bulletin as an older polyethylene pipe material that is susceptible to SCG. A majority of the system leaks experienced were found to be attributed to SCG. The flowchart suggests that the operator take some type of additional or accelerated (A/A) action such as those suggested in GPTC DIMP Table 6.1 in order to appropriately manage the threat and minimize the risk. The A/A actions in this table are not meant to be restrictive, but instead are meant to serve as suggestions. The operator is free to take any action that helps reduce the risk of the SCG threat to the system.

After an action is applied, the operator should monitor the trend of leaks occurring due to SCG to determine if they are increasing, decreasing, or remaining the same. In this particular case,

after the operator applied an A/A action the trend of leaks began to decrease signifying that the A/A action was effective. Had the trend stayed the same or continued to increase, the flowchart would direct the operator to implement another A/A action in a further effort to manage the leaks still occurring. After a decline in the leak trend is seen, the operator should continue to implement the A/A action found to be most effective at mitigating the leaks, and use any new knowledge it gained to monitor the performance of the main. Going forward, the operator should continue to operate and maintain the segment in accordance with Part 192, Subpart P and with the operator's Distribution Integrity Management Program (DIMP). Additionally, the operator should be resolute in determining the source of the local stress intensification, which caused the leaks, in order to prevent similar leaks from occurring in the future. After the threat of in-service failures attributed to SCG has been addressed, the operator should refer back to Flowchart START (for plastic gas distribution main) and assess the other threats to which the system is susceptible.

Returning to Flowchart START (for plastic gas distribution main), the operator of this main should assess the other applicable threat, which is joining or tap connection type failures. Flowchart PLASTIC CONNECTIONS, shown in Figure 40, should be used to analyze this threat.

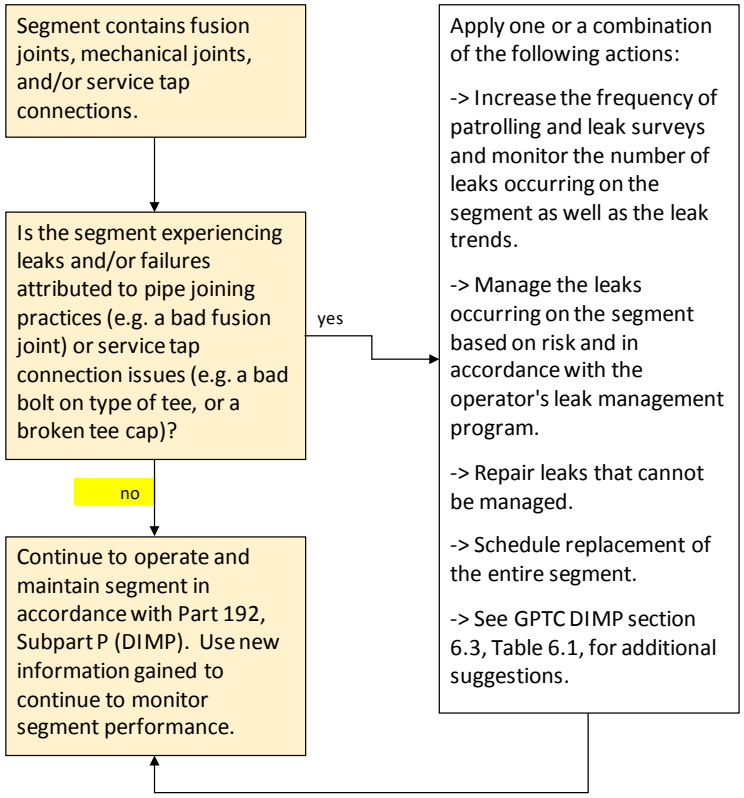


Figure 40. Feasibility of Preventing in-Service Failures from Joining or Tap Connection type Failures in a Plastic Main

According to Figure 40, this distribution system contains fusion or mechanical joints and/or service tap connections; however the system is not currently experiencing any issues with these types of connections (e.g. a bad fusion joint, or a bad bolt on tee). Since the system is not experiencing leaks due to this threat, the operator is able to continue to operate and maintain the segment in accordance with the DIMP regulations. Had the system been experiencing leaks attributed to joining or connection type issues, the operator would need to take an A/A action to manage the leaks along the line to maintain integrity and to ensure safety. The operator's capability of addressing these connection type issues as well as the costs associated with remediation would determine whether they could be properly managed or if replacement would be necessary.

The above analysis indicates that the threats to the integrity of the distribution system described are being mitigated through the applied A/A actions being taken by the operator. Judging whether the operator should continue to apply these A/A actions and continue to operate the system going forward versus replacing it can be decided on a basis that includes the cost of maintaining pipeline integrity and safety. The cost to maintain and reassess the system to a level required for mitigating risk to assure safety depends on the costs of the various A/A actions discussed above. If these continuing costs are acceptable to the operator, then replacement is not necessary.

Base Case Example No. 6: A Cast Iron Gas Distribution Main

Consider the cast iron natural gas distribution main described in Table 8. It is comprised of 4.80-inch-OD, 0.48-inch-wall, Class A pipe manufactured and installed in 1925. The distribution main is approximately 9.5 miles long. The MAOP of the pipeline is 25 psig.

The operator has no records documenting the pipeline's design and construction in 1925. However, operating records show that all pipe joints along this main have been sealed, and no leaks have been experienced after the sealing process was complete. The leak history indicates that leaks due to graphitization and breakage have been generally increasing since 1967.

There is no record of a post construction pressure test for this main. Since the distribution main is directly connected to the end users through hundreds of service connections, service cannot be interrupted. For this reason, the main cannot be taken out of service to perform a pressure test, and it cannot accommodate an in-line inspection tool.

To determine whether or not this main should be replaced, the operator can go through the process described below starting with Flowchart START (for cast iron distribution main) (Figure C24 of Appendix C). Flowchart START (for cast iron distribution main) is repeated as Figure 41 below as adapted to this particular pipeline.

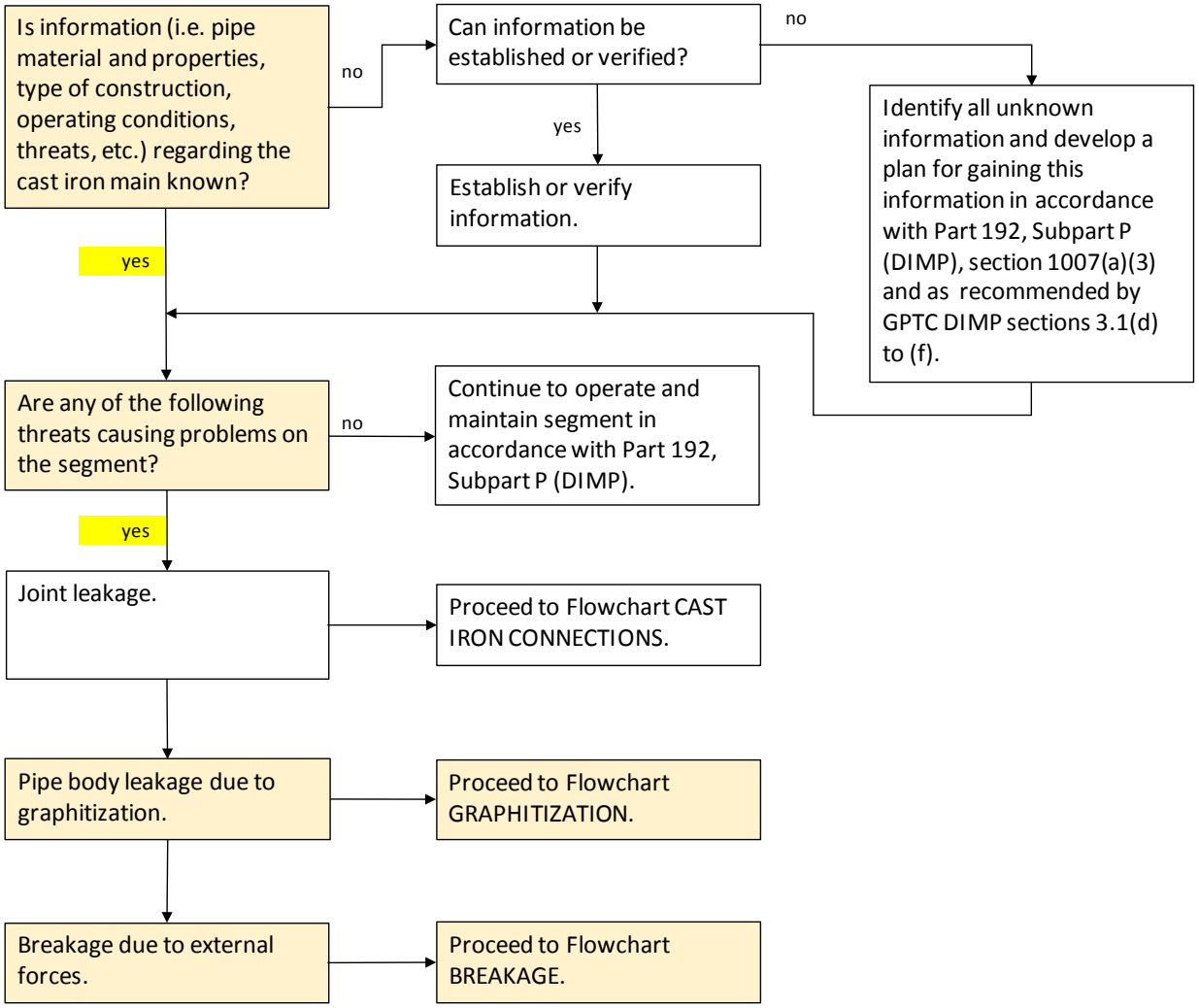


Figure 41. Start of Process to Decide Whether to Repair or Replace the Base Case involving a Cast Iron Distribution Main

The diameter, thickness, and type of material of this main are known because of the earlier joint-sealing work. Thus, even though the operator does not have original design and construction records, the susceptibility to known integrity threats can be assessed. If diameter, wall thickness, seam type, or specified minimum yield strength were not known, the operator would have to identify all unknown information and develop a plan for gaining this information in accordance with Part 192, Subpart P (DIMP), section 1007(a)(3) and as recommended by GPTC DIMP sections 3.1(d) to (f).

The segment has been experiencing leaks due to graphitization. So, the next step is to proceed to Figure 42 which is Flowchart GRAPHITIZATION (Figure C26 of Appendix C).

Any cast iron distribution main may be susceptible to breakage from external forces such as soil movement; therefore, after assessing the segment for a graphitization threat, the operator should proceed to Flowchart BREAKAGE (Figure C27 of Appendix C), shown in Figure 43, to assess the segment for a breakage threat accordingly.

This base case pipeline is not experiencing leaks in any of its joint connections, so the operator of this pipeline need not consider the threats represented in Flowchart CAST IRON CONNECTIONS (Figure C25 of Appendix C).

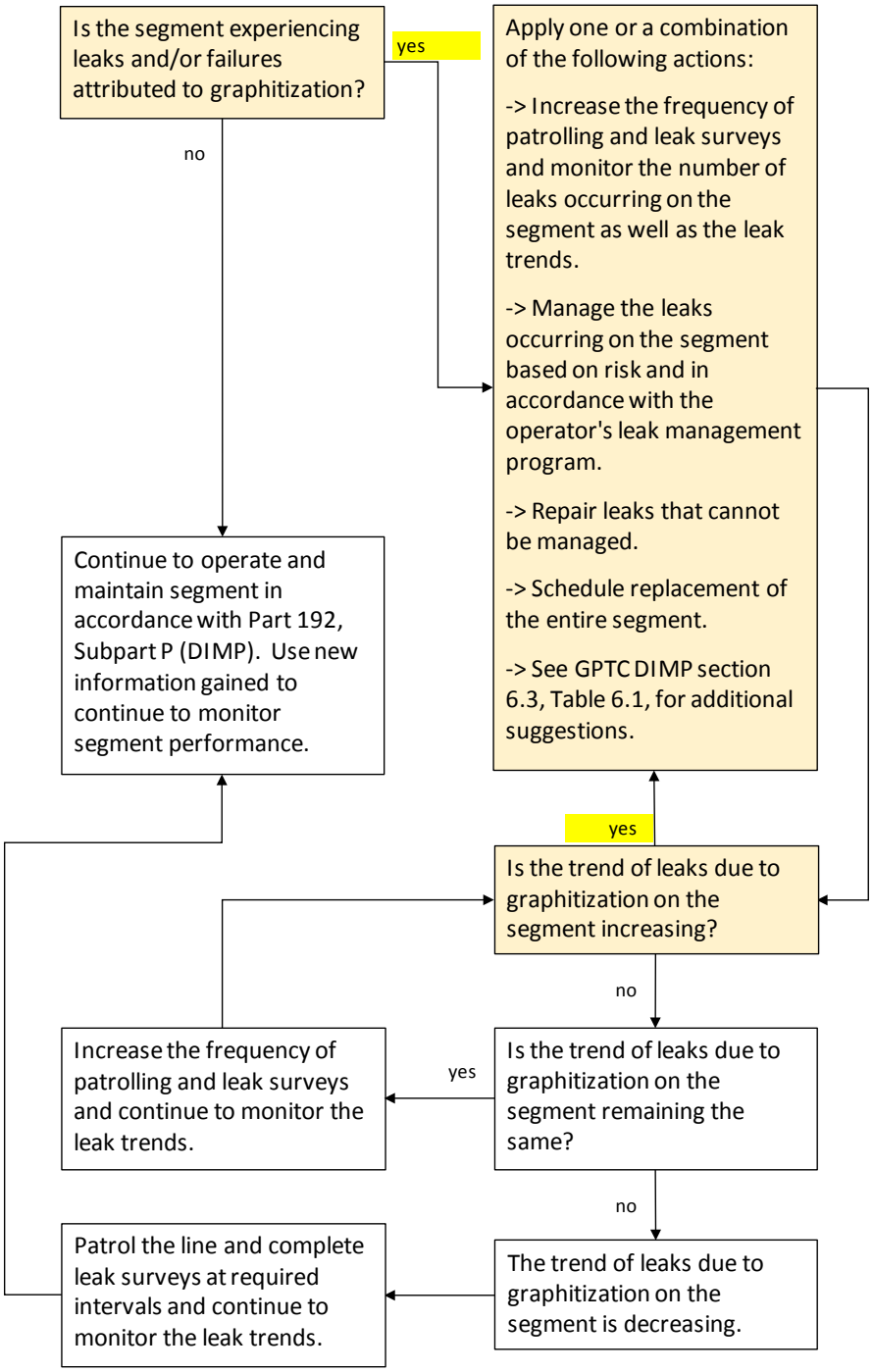


Figure 42. Feasibility of Preventing in-Service Failures from Graphitization

According to Figure 42, the operator has confirmed that the main is experiencing leaks due to graphitization. The flowchart suggests that the operator take some type of additional or accelerated (A/A) action such as those suggested in GPTC DIMP Table 6.1 in order to appropriately manage the threat and minimize the risk. The A/A actions in this table are not meant to be restrictive, but instead are meant to serve as suggestions. The operator is free to

take any action that helps reduce the risk of the graphitization threat to the system. After taking the first A/A action, the operator notes the leak trend is still continuing to increase. The flowchart directs the operator to take a second A/A action after which the operator again notes the leak trend is increasing. At this point, the flow chart will continue to recommend that the operator apply A/A actions until the trend of leaks on the system begins to decrease. Although the operator of this particular main continues to apply A/A actions, no improvement is seen. Based on the various locations along the main in which the issue is occurring, along with the seemingly advanced nature of the graphitization, the operator concludes that the problem is systemic. Due to its advanced nature, more drastic actions such as a major repair program or replacement will have to be implemented in order to mitigate the threat and to assure continued safe operation of the main. Had the trend of graphitization leaks in this particular case responded to one of the A/A actions applied, the operator may have been able to continue to operate and maintain the segment going forward in accordance with the DIMP regulations.

Returning to Flowchart START (for cast iron distribution main), the operator of this main should assess the last applicable threat, which is breakage due to external forces. Flowchart BREAKAGE, shown in Figure 43, should be used to analyze this threat.

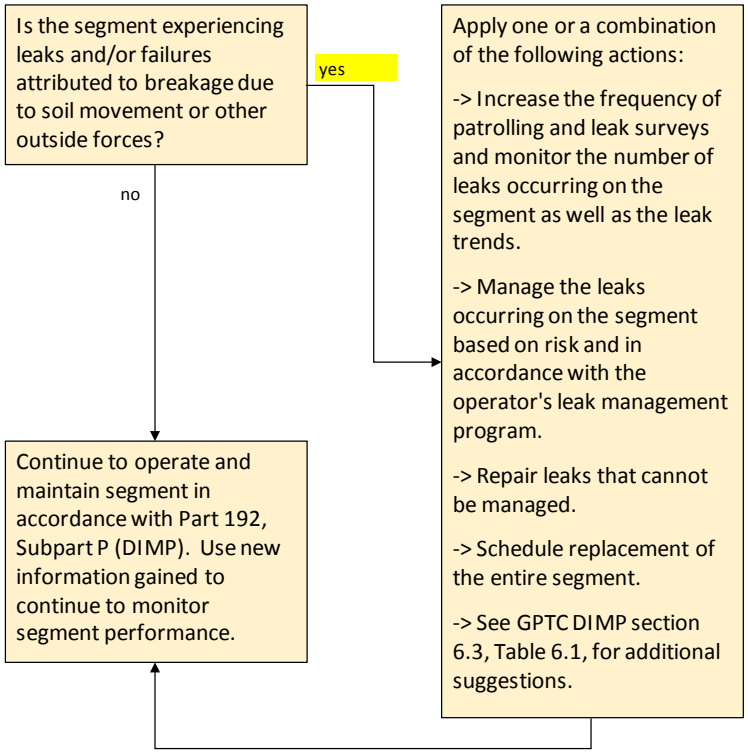


Figure 43. Feasibility of Preventing in-Service Failures from Breakage due to Soil Movement

According to Figure 43, the operator confirmed that the main is experiencing breakage-type leaks due to soil movement in isolated locations along the line. The operator should take an A/A action such as increasing the frequency of patrolling and leak surveys, while managing the breakage-type leaks based on risk and in accordance with its leak management program. With the knowledge that this type of failure is only occurring in isolated locations, the operator may be able to address the threat either by stabilizing the soil movement problem or by replacing the cast iron only in the locations where soil movement is known to occur. Any new information gained throughout the DIMP process such as knowledge regarding soil movement should be used to continue to monitor the segment's performance. After the threat of the breakage-type leaks has been addressed, the operator will be able to continue to operate and maintain the segment in accordance with the DIMP regulations.

The above analysis indicates that the threats to the integrity of this main cannot be appropriately mitigated through repairs or on-going maintenance and integrity assessment actions taken by the operator. The severe graphitization threat that the operator has been unable to mitigate along with the breakage-type leaks occurring in locations with known susceptibility to soil movement suggest that replacement of this particular main is the most appropriate mitigative response.

APPENDIX A - PIPELINE MILEAGE INSTALLED BY AGE

The following tables show the mileage by decade installed of pre-regulation (pre-1970) pipe reported by pipeline operators in annual reports to PHMSA from 2005 through 2012. These data may be accessed through the following website.

http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=78e4f5448a359310VgnVCM1000001ecb7898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print&vgnextnoice=1

From each table trends are plotted which show (in spite of year-to-year variations that probably reflect changes in reporting parameters) that the mileages of pre-regulation pipe and mains and numbers of pre-regulation services have decreased over the 2005-2012 time period. It is assumed that the downward trends result from older pipelines being replaced.

Table A1. Miles of Hazardous Liquid Pipelines by Decade of Installation

Calendar Year	Pre-20 or Unknown	1920-1929	1930-1939	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	Total Miles
2,005	1,377.21	3,034.48	6,343.91	16,819.16	36,036.70	35,586.28	27,468.01	16,990.63	18,095.63	5,013.45		166,765.45
2,006	1,424.03	2,847.21	5,797.98	17,098.78	35,698.46	33,195.64	28,889.86	17,384.29	17,734.80	6,647.81		166,718.88
2,007	1,560.55	2,720.75	5,563.39	15,698.11	36,668.23	33,271.18	28,570.00	18,126.93	18,839.30	8,827.68		169,846.13
2,008	1,569.38	2,896.92	5,686.31	15,500.35	37,400.46	34,527.29	29,302.99	17,921.39	18,360.49	10,623.49		173,789.06
2,009	4,170.42	2,894.73	5,840.64	14,944.67	35,113.40	35,906.24	27,480.69	17,027.30	18,613.62	13,973.78		175,965.48
2,010	5,227.19	2,899.78	4,681.80	14,911.53	32,392.77	35,105.71	30,818.69	18,120.56	18,380.74	17,521.58	1,913.61	181,973.95
2,011	5,953.99	2,894.35	4,681.23	15,490.66	33,967.83	34,316.64	30,315.71	17,183.18	19,234.99	16,832.83	2,510.97	183,382.38
2,012	6,017.79	2,573.77	4,700.37	15,544.60	34,659.09	33,921.74	29,991.11	17,238.21	19,056.42	16,926.58	5,393.98	186,023.64

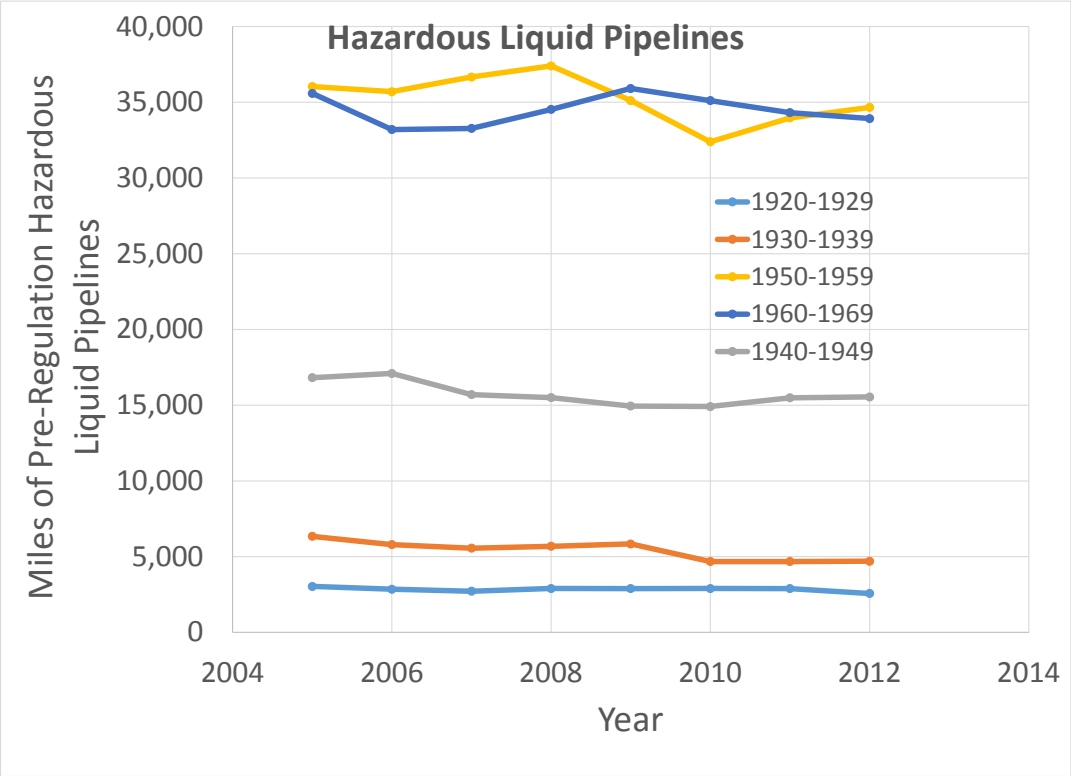


Figure A1. Trends in the Amounts of Pre-Regulation Pipe in Hazardous Liquid Pipelines (2005-2012)

Table A2. Miles of Natural Gas Transmission Pipelines by Decade of Installation

Calendar Year	Pre 1940 or Unknown	1940 - 1949	1950 - 1959	1960 - 1969	1970 - 1979	1980 - 1989	1990 - 1999	2000 - 2009	2010 - 2019	Total Miles
2,005	21,831.84	24,137.24	72,734.08	74,238.21	32,301.31	28,251.67	31,902.26	15,071.46		300,468.07
2,006	20,869.48	24,095.86	71,008.44	73,975.64	32,313.87	27,624.05	32,316.05	18,120.76		300,324.14
2,007	20,404.81	23,867.73	71,842.22	73,022.16	32,306.28	27,650.68	32,074.42	19,897.87		301,066.17
2,008	18,105.61	22,912.97	72,118.63	73,598.07	32,134.98	27,613.03	32,128.72	24,568.99		303,181.00
2,009	16,775.15	22,657.10	71,391.02	73,187.76	32,375.38	27,383.50	32,340.08	28,462.94		304,572.93
2,010	17,221.68	22,653.36	69,971.38	72,442.01	31,991.01	26,921.15	31,858.39	29,727.34	1,988.78	304,775.10
2,011	14,950.79	22,571.84	69,903.11	72,230.49	32,267.36	26,455.82	31,624.38	30,009.18	5,023.12	305,036.08
2,012	14,517.04	22,041.40	68,813.06	72,027.59	31,686.20	26,034.08	30,856.42	30,463.21	6,893.53	303,332.54

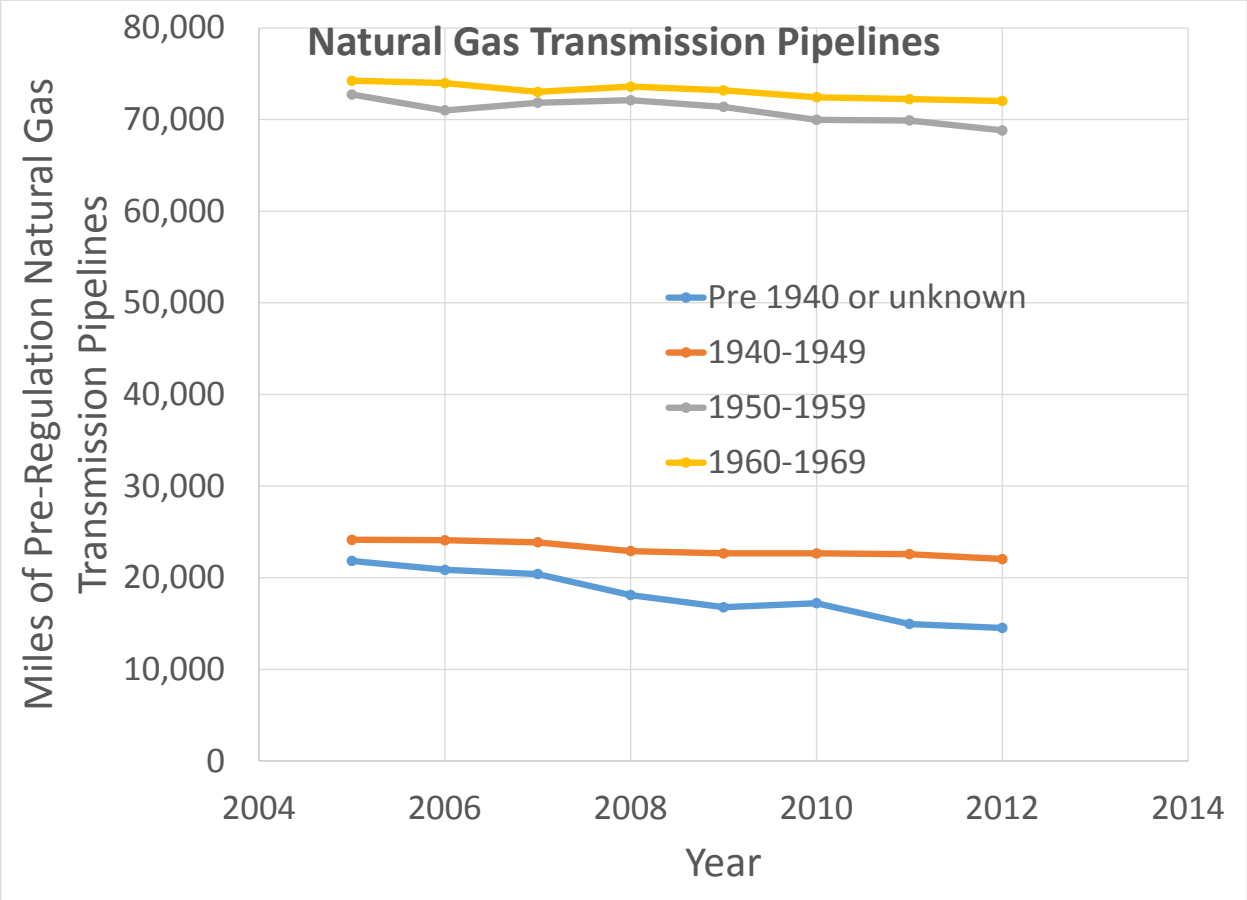


Figure A2. Trends in the Amounts of Pre-Regulation Pipe in Natural Gas Transmission Pipelines (2005-2012)

Table A3. Miles of Natural Gas Distribution Mains by Decade of Installation

	Unknown	Pre 1940s	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	Total Miles
Year											
2,005	124,218.36	71,510.58	27,459.02	107,728.93	193,304.76	128,550.42	150,752.22	228,397.21	133,135.48		1,165,057.00
2,006	122,174.91	68,784.34	27,231.90	107,623.25	193,428.56	128,955.48	151,285.90	229,932.65	158,614.85		1,188,031.83
2,007	91,362.21	71,062.39	26,890.36	108,265.70	197,729.42	133,436.08	156,236.61	234,219.58	184,093.89		1,203,296.24
2,008	88,353.78	70,425.24	26,825.59	108,955.49	195,247.18	132,990.80	156,989.26	232,726.22	197,370.50		1,209,884.07
2,009	85,988.93	68,553.48	26,547.58	108,434.19	198,888.09	132,505.21	156,821.45	233,972.06	208,658.22		1,220,369.20
2,010	76,176.44	66,964.24	26,470.76	110,288.11	200,645.10	134,239.19	157,845.21	236,920.05	208,637.52	11,114.16	1,229,300.77
2,011	99,201.84	63,090.22	25,419.02	105,192.35	195,221.46	130,494.70	154,632.62	236,319.96	206,998.64	22,000.53	1,238,571.34
2,012	93,972.79	60,131.37	25,418.14	106,160.99	195,008.60	131,581.18	155,705.38	236,399.66	207,129.95	35,338.18	1,246,846.23
2,013	96,620.57	58,958.33	25,232.27	102,926.39	191,794.87	131,739.17	154,911.51	234,778.48	206,458.30	49,887.84	1,253,307.74

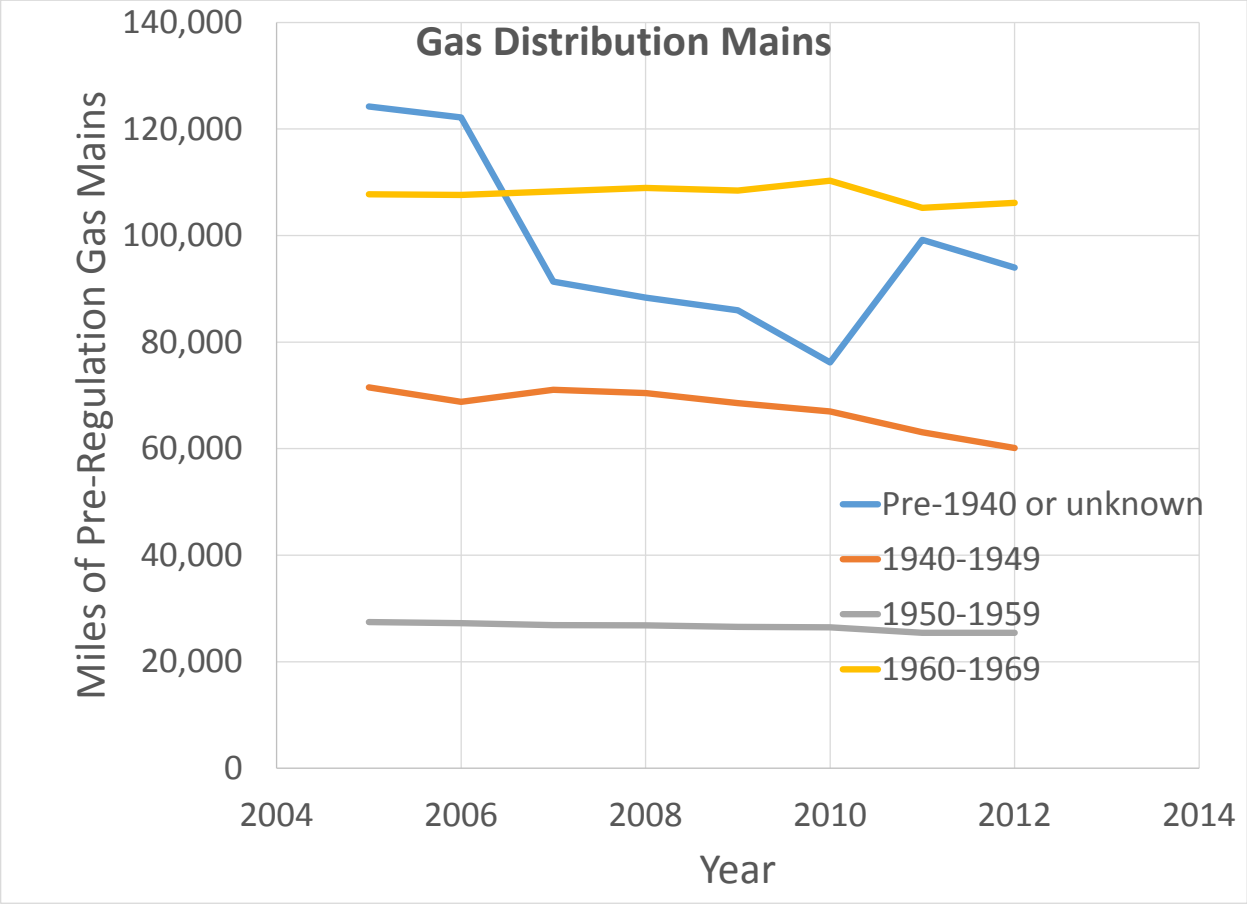


Figure A3. Trends in the Amounts of Pre-Regulation Natural Gas Distribution Mains (2005-2012)

Table A4. Number of Natural Gas Distribution Services by Decade of Installation

	Unknown	Pre-1940s	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-1999	2000-2009	2010-2019	Total Services
Year											
2005	8,796,749	2,226,803	1,267,203	4,752,717	7,913,840	8,220,076	9,615,676	12,568,061	7,643,953		63,005,078
2006	8,543,258	2,103,602	1,254,899	4,706,143	7,857,407	8,252,816	9,632,179	12,696,178	9,103,616		64,150,098
2007	7,368,330	2,059,634	1,209,080	4,615,020	7,849,059	8,455,123	9,784,113	12,939,711	10,584,043		64,864,113
2008	6,747,807	1,959,971	1,199,514	4,626,829	7,811,142	8,442,645	9,847,813	12,869,539	11,881,499		65,386,759
2009	5,549,515	1,942,976	1,219,358	4,631,658	7,808,206	8,490,444	9,981,694	13,009,388	12,951,278		65,584,517
2010	5,818,364	1,910,390	1,219,165	4,601,660	7,455,020	8,385,022	9,903,986	12,924,407	12,936,848	758,838	65,913,700
2011	5,479,549	1,825,596	1,190,529	4,585,953	7,468,279	8,416,633	9,964,499	13,004,886	12,951,199	1,578,864	66,465,987
2012	5,276,672	1,767,856	1,155,708	4,506,933	7,372,835	8,336,979	9,925,605	12,901,590	12,882,628	2,549,992	66,676,798
2013	5,118,867	1,689,578	1,121,772	4,398,773	7,176,610	8,198,680	9,845,732	12,936,388	12,974,841	3,653,575	67,114,816

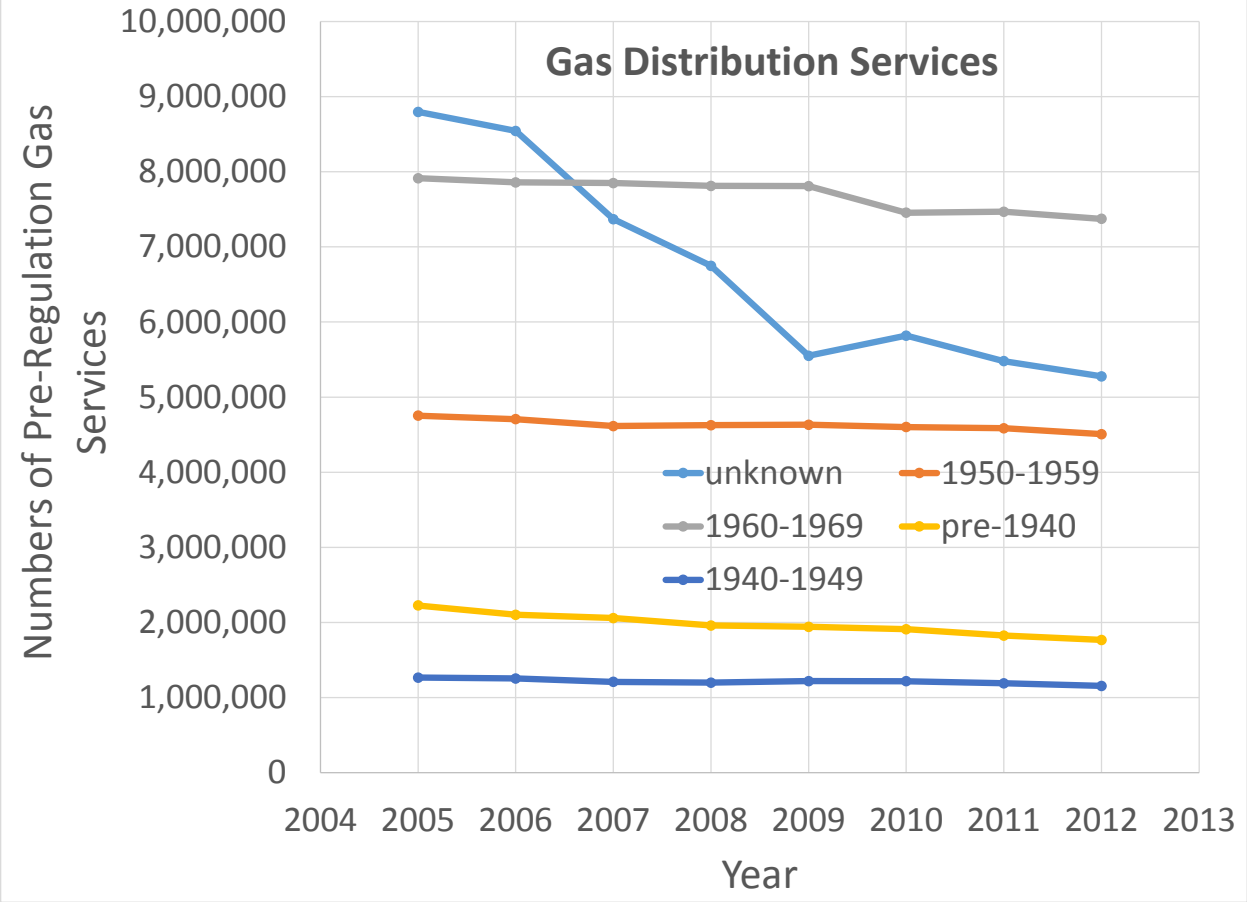


Figure A4. Trends in the Numbers of Pre-Regulation Natural Gas Distribution Services (2005-2012)

APPENDIX B - DETAILS OF REPORTABLE INCIDENTS BY CAUSE

These data may be accessed through the following website.

http://www.phmsa.dot.gov/portal/site/PHMSA/menuitem.6f23687cf7b00b0f22e4c6962d9c8789/?vgnextoid=78e4f5448a359310VgnVCM1000001ecb7898RCRD&vgnextchannel=3430fb649a2dc110VgnVCM1000009ed07898RCRD&vgnextfmt=print&vgnextnoice=1

Table B1. Reportable Incidents by Cause 1994-2013 – Part 1 of 2

CAUSE OR THREAT	NUMBER			PERCENT		
	HAZARDOUS LIQUID	NATURAL GAS TRANSMISSION	NATURAL GAS DISTRIBUTION	HAZARDOUS LIQUID	NATURAL GAS TRANSMISSION	NATURAL GAS DISTRIBUTION
CORROSION						
EXTERNAL CORROSION	259	100	30	7.17%	8.57%	2.18%
INTERNAL CORROSION	354	131	1	9.81%	11.23%	0.07%
UNSPECIFIED CORROSION	195			5.40%		
Sub Total for CORROSION	808	231	31	22.38%	19.79%	2.25%
EXCAVATION DAMAGE						
OPERATOR/CONTRACTOR EXCAVATION DAMAGE	45	29	25	1.25%	2.49%	1.81%
THIRD PARTY EXCAVATION DAMAGE	125	138	389	3.46%	11.83%	28.23%
PREVIOUS DAMAGE DUE TO EXCAVATION	8	9	2	0.22%	0.77%	0.15%
UNSPECIFIED EXCAVATION DAMAGE	12			0.33%		
Sub Total EXCAVATION DAMAGE	190	176	416	5.26%	15.08%	30.19%
INCORRECT OPERATION						
DAMAGE BY OPERATOR OR OPERATOR'S CONTRACTOR	10	1	5	0.28%		0.36%
OVERFILL/OVERFLOW OF TANK/VESSEL/SUMP	40			1.11%		
INCORRECT VALVE POSITION	38	6	4	1.05%	0.51%	0.29%
PIPELINE/EQUIPMENT OVERPRESSURED	24	2		0.66%	0.17%	
INCORRECT INSTALLATION	32	1	5	0.89%	0.09%	0.36%
INCORRECT EQUIPMENT	4			0.11%		
OTHER INCORRECT OPERATION	36	13	14	1.00%	1.11%	1.02%
UNSPECIFIED INCORRECT OPERATION	230	16	29	6.37%	1.37%	2.10%
Sub Total for INCORRECT OPERATION	414	39	57	11.47%	3.26%	4.14%
MAT'L/WELD/FAILURE						
CONSTRUCTION INSTALLATION OR FABRICATION-RELATED	65	30		1.80%	2.57%	
MANUFACTURING-RELATED	41	19		1.14%	1.63%	
ENVIRONMENTAL CRACKING-RELATED	20	14		0.55%	1.20%	
BODY OF PIPE	25	18	18	0.69%	1.54%	1.31%
PIPE SEAM	37	11		1.02%	0.94%	
UNSPECIFIED PIPE BODY OR SEAM				0.00%		
BUTT WELD	23	30	2	0.64%	2.57%	0.15%
FUSION JOINT			2			0.15%
COMPRESSION FITTING			2			0.15%
MECHANICAL FITTING			7			0.51%
FILLET WELD	14	7		0.39%	0.60%	
UNSPECIFIED WELD						
JOINT/FITTING/COMPONENT	75	40	27	2.08%	3.43%	1.96%
UNSPECIFIED MAT'L/WELD FAILURE	108		5	2.99%		0.36%
OTHER PIPE/WELD/JOINT FAILURE			5			0.36%
Sub Total for MATERIAL/WELD/FAILURE	408	169	68	11.30%	14.48%	4.93%

FINAL
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Table B1. Reportable Incidents by Cause 1994-2013 – Part 2 of 2

CAUSE OR THREAT	NUMBER			PERCENT		
	HAZARDOUS LIQUID	NATURAL GAS TRANSMISSION	NATURAL GAS DISTRIBUTION	HAZARDOUS LIQUID	NATURAL GAS TRANSMISSION	NATURAL GAS DISTRIBUTION
EQUIPMENT FAILURE						
MALFUNCTION OF CONTROL/RELIEF EQUIPMENT	129	108	19	3.57%	9.25%	1.38%
VALVE			6			0.44%
PUMP/COMPRESSOR-RELATED EQUIPMENT	167	10		4.63%	0.86%	
THREADED CONNECTION/COUPLING FAILURE	120	30	4	3.32%	2.57%	0.29%
NON-THREADED CONNECTION FAILURE	227	12	11	6.29%	1.03%	0.80%
DEFECTIVE OR LOOSE TUBING/FITTING	35	1		0.97%	0.09%	
FAILURE OF EQUIPMENT BODY	32	4		0.89%	0.34%	
OTHER EQUIPMENT FAILURE	112	11		3.10%	0.94%	
UNSPECIFIED EQUIPMENT FAILURE	506			14.02%		
Sub Total for EQUIPMENT FAILURE	1328	176	40	36.79%	15.08%	2.90%
NATURAL FORCE DAMAGE						
EARTH MOVEMENT	19	23	28	0.53%	1.97%	2.03%
HEAVY RAINS/FLOODS	31	90	27	0.86%	7.71%	1.96%
LIGHTNING	20	17	19	0.55%	1.46%	1.38%
TEMPERATURE	53	10	17	1.47%	0.86%	1.23%
HIGH WINDS	30	14	11	0.83%	1.20%	0.80%
OTHER NATURAL FORCE DAMAGE	4	4	5	0.11%	0.34%	0.36%
UNSPECIFIED NATURAL FORCE DAMAGE	35		1	0.97%		0.07%
Sub Total for NATURAL FORCE DAMAGE	192	158	108	5.32%	13.54%	7.84%
OTHER OUTSIDE FORCE DAMAGE						
FIRE/EXPLOSION AS PRIMARY CAUSE	5	12	227	0.14%	1.03%	16.47%
VEHICLE NOT ENGAGED IN EXCAVATION	26	63	161	0.72%	5.40%	11.68%
MARITIME EQUIPMENT OR VESSEL ADRIFT	1	1		0.03%	0.09%	
FISHING OR MARITIME ACTIVITY	1	7		0.03%	0.60%	
ELECTRICAL ARCING FROM OTHER EQUIPMENT/FACILITY	6	2	11	0.17%	0.17%	0.80%
PREVIOUS MECHANICAL DAMAGE	8	7	5	0.22%	0.60%	0.36%
INTENTIONAL DAMAGE	7	3	17	0.19%	0.26%	1.23%
OTHER OUTSIDE FORCE DAMAGE	8	9	24	0.22%	0.77%	1.74%
UNSPECIFIED OUTSIDE FORCE DAMAGE	19		5	0.53%		0.36%
Sub Total for OTHER OUTSIDE FORCE DAMAGE	81	104	450	2.24%	8.91%	32.66%
ALL OTHER CAUSES						
MISCELLANEOUS CAUSE	120	88	101	3.32%	7.54%	7.33%
UNKNOWN CAUSE	34	26	107	0.94%	2.23%	7.76%
UNSPECIFIED	35			0.97%		
Sub Total for ALL OTHER CAUSES	189	114	208	5.24%	9.77%	15.09%
Totals	3610	1167	1378	100.00%	99.91%	100.00%

APPENDIX C - FLOWCHARTS

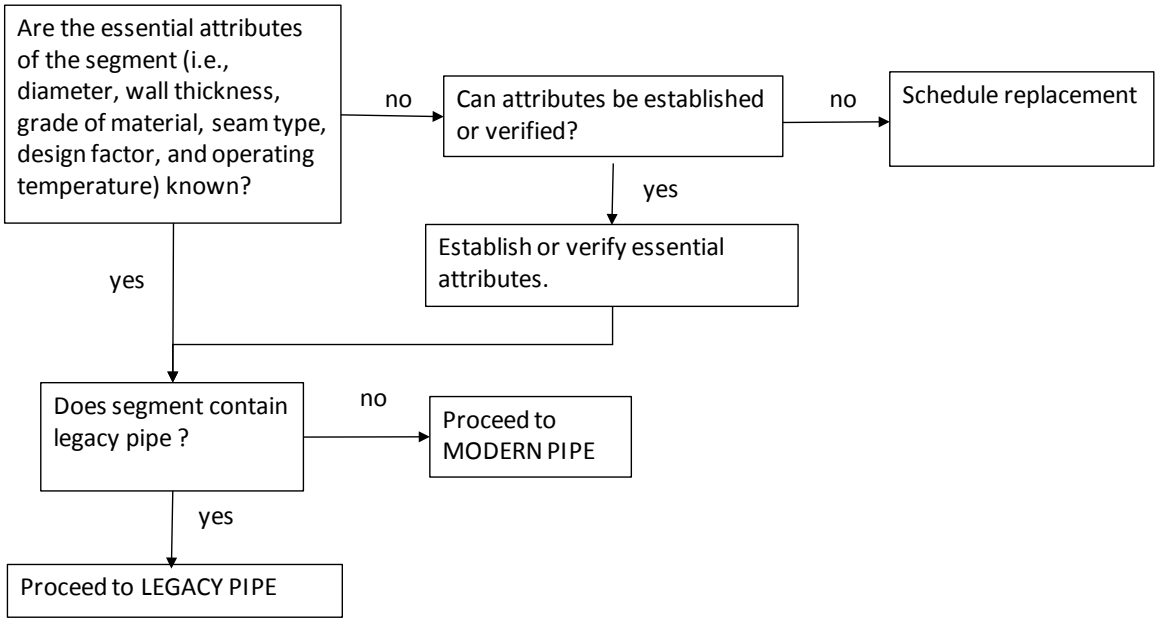


Figure C1. Flowchart START (for hazardous liquid pipelines, high-stress natural gas transmission pipelines, and low-stress natural gas transmission pipelines)

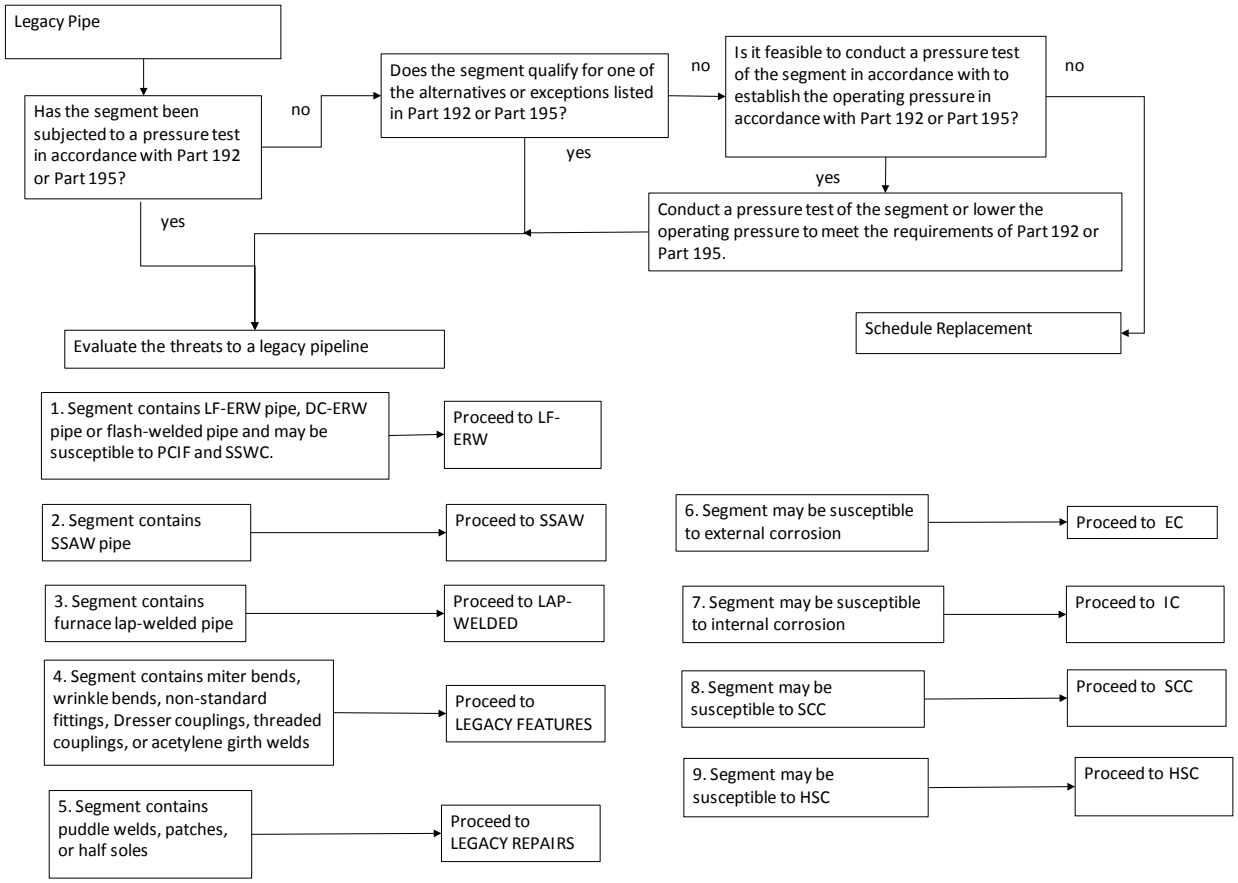


Figure C2. Flowchart LEGACY PIPE

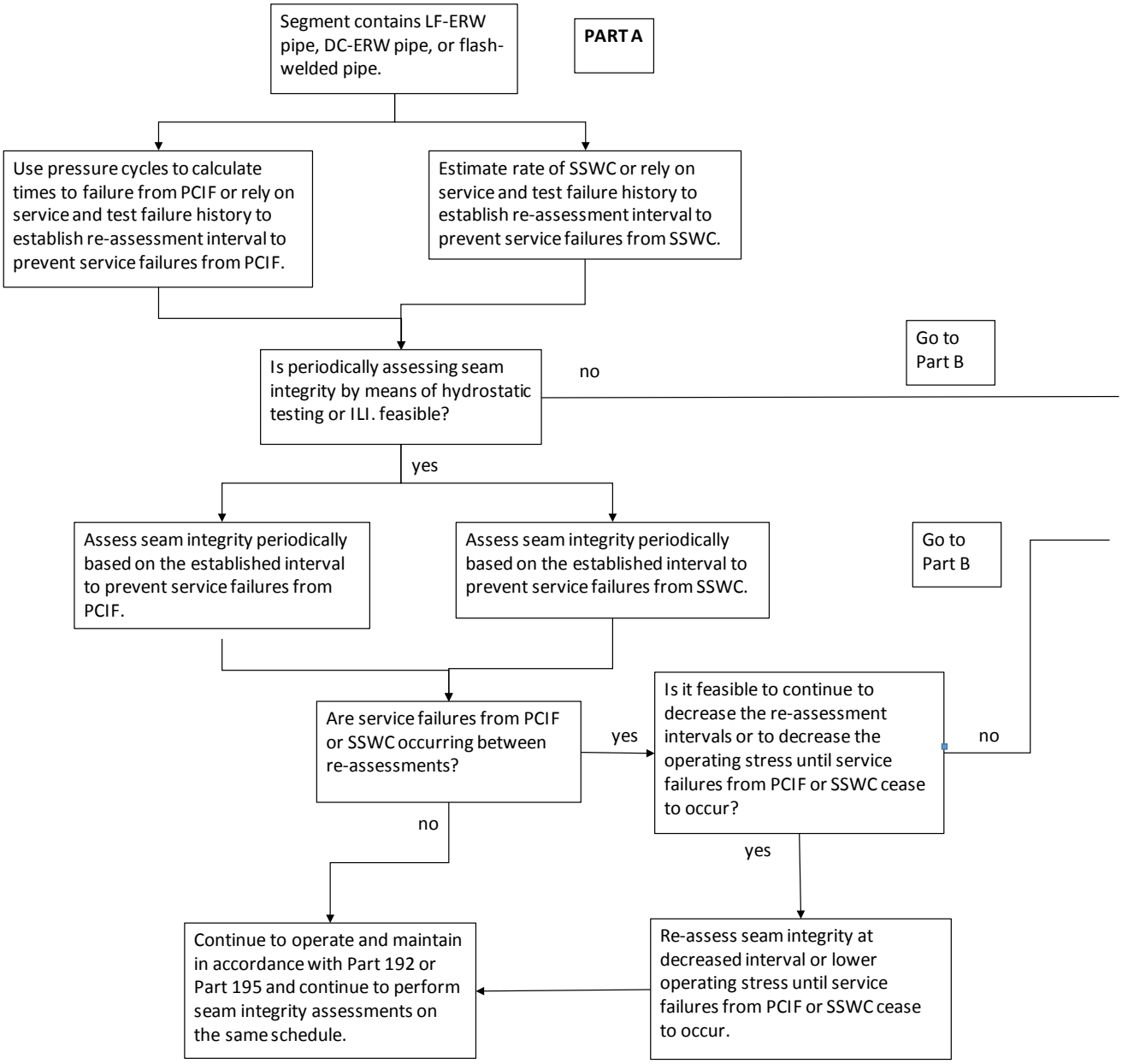


Figure C3A. Flowchart LF ERW (Part A)

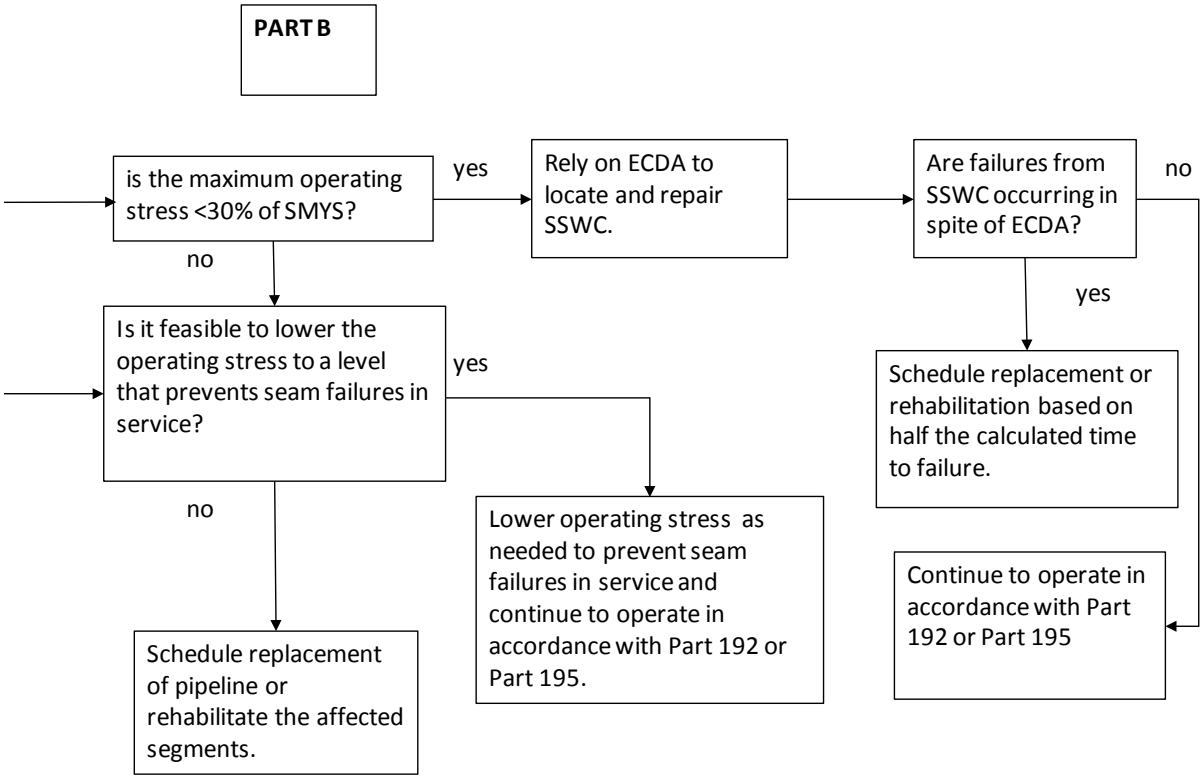


Figure C3B. Flowchart LF ERW (Part B)

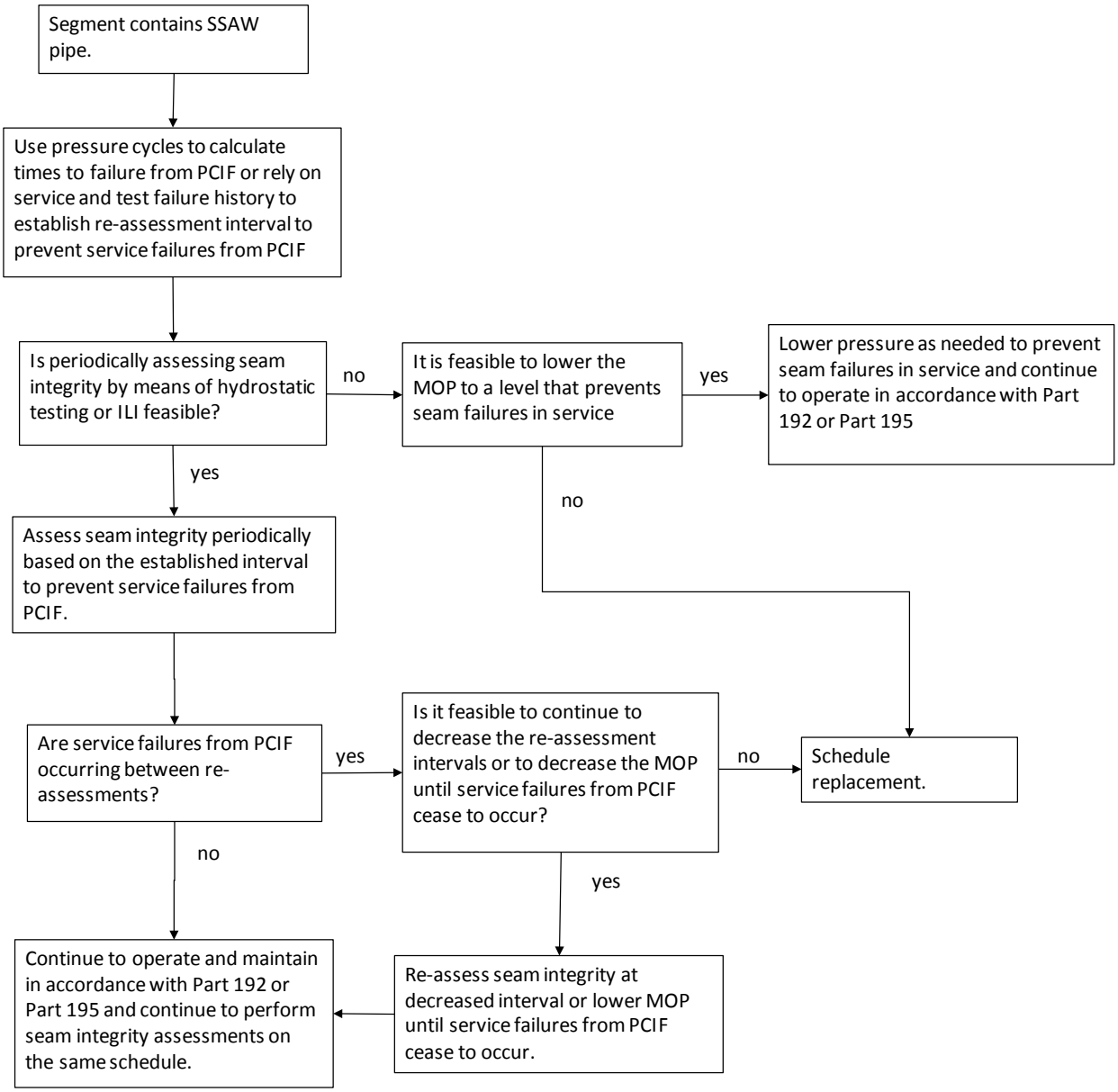


Figure C4. Flowchart SSAW

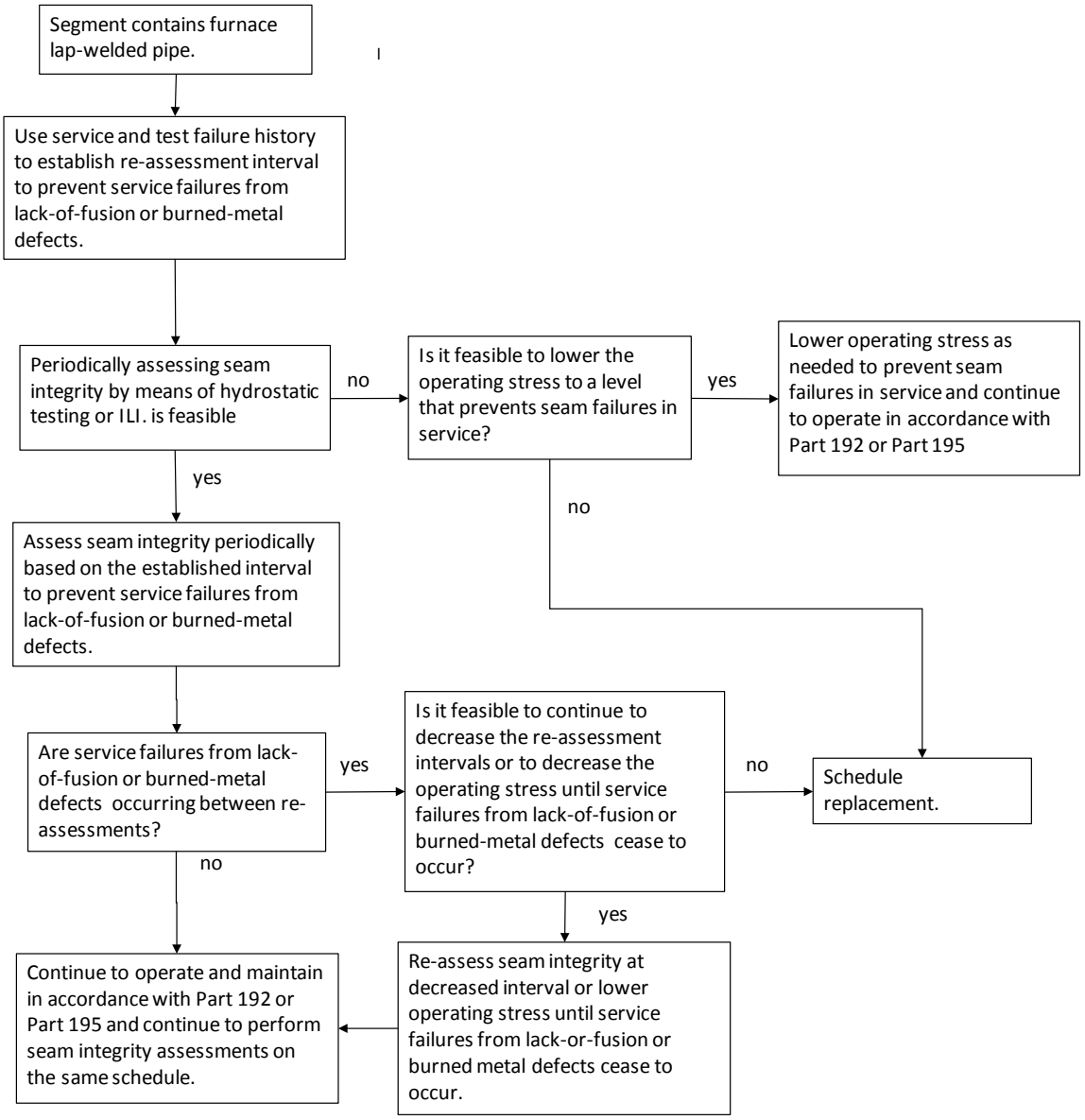


Figure C5. Flowchart LAP-WELDED

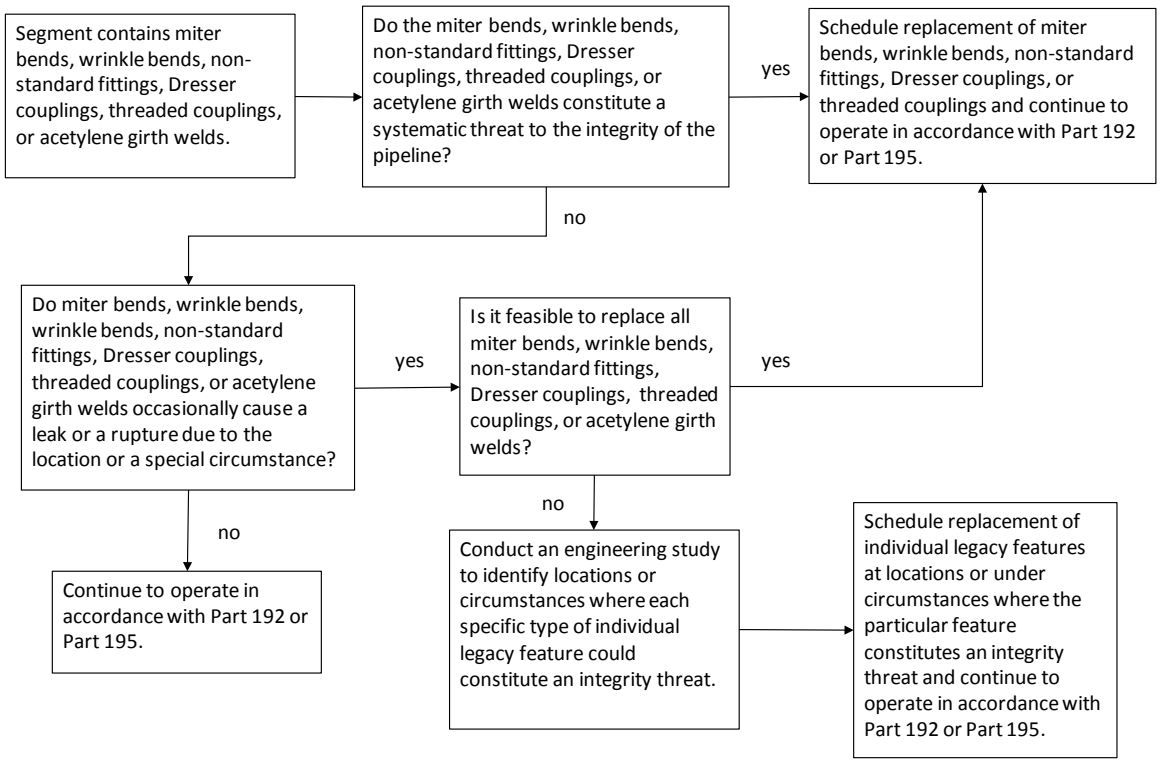
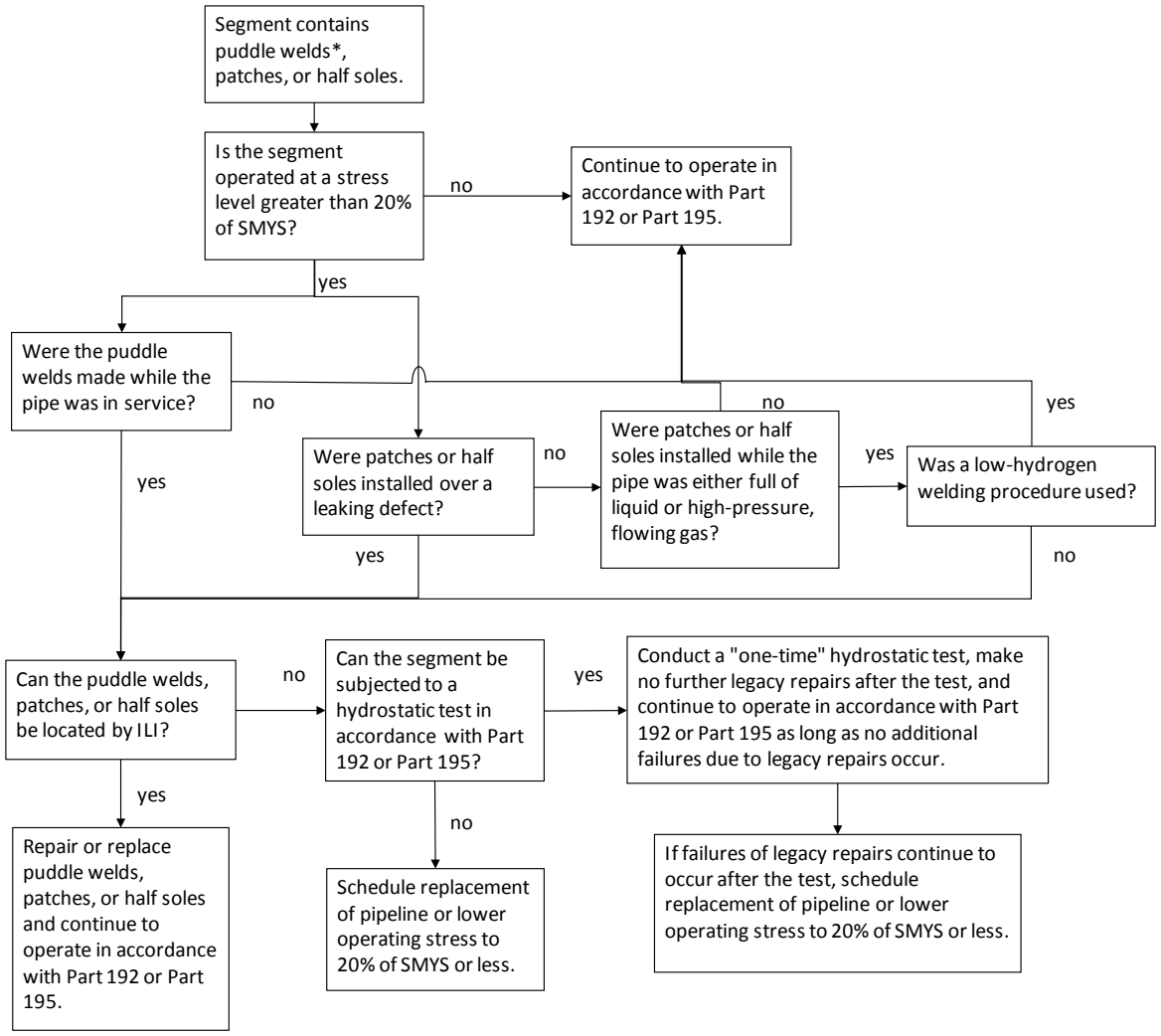


Figure C6. Flowchart LEGACY FEATURES



*Puddle welding refers to welds made with an unknown welding proceddure to repair pits or other defects. Deposited weld metal repairs made according to a documented and proven procedure are a legitimate repair method and do not fall under this definitaion of puddle welding.

Figure C7. Flowchart LEGACY REPAIRS

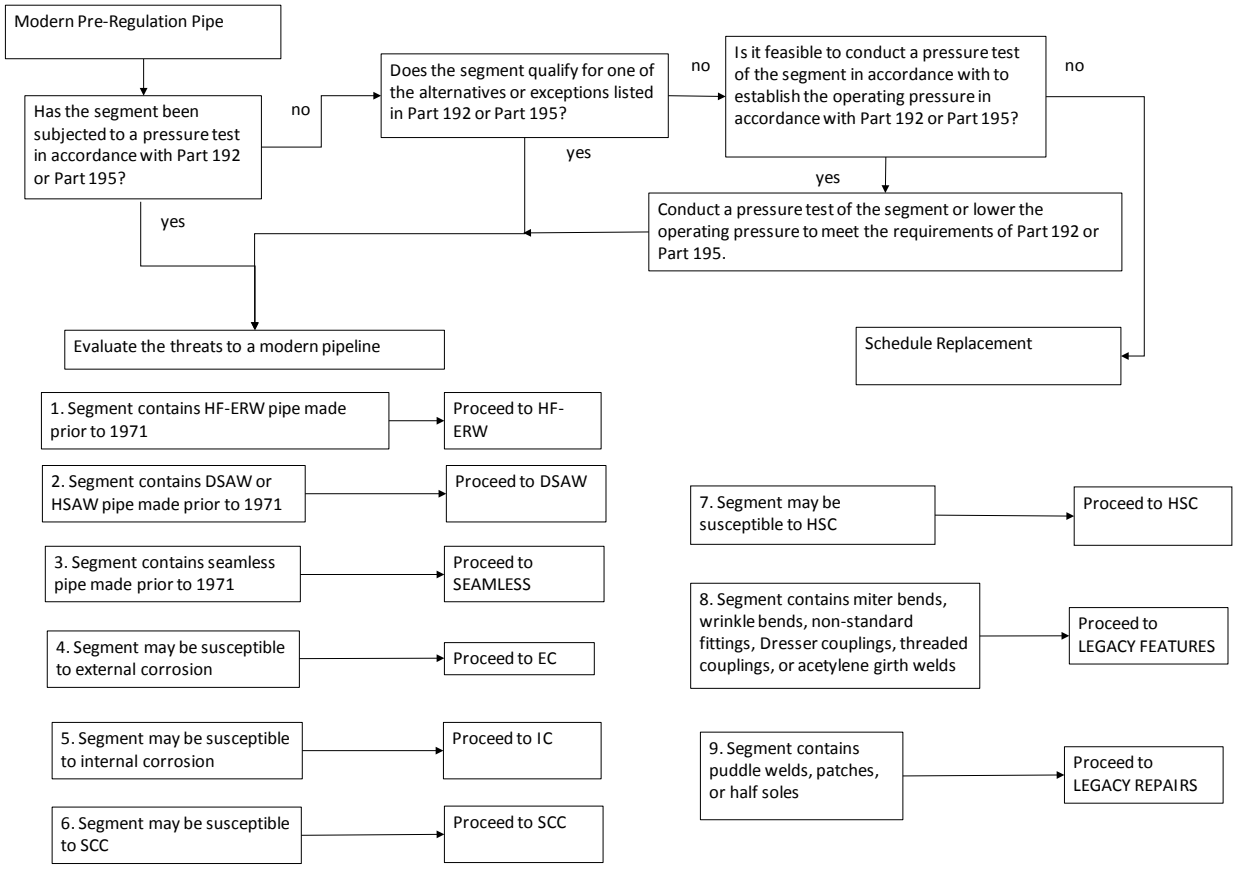


Figure C8. Flowchart MODERN PIPE

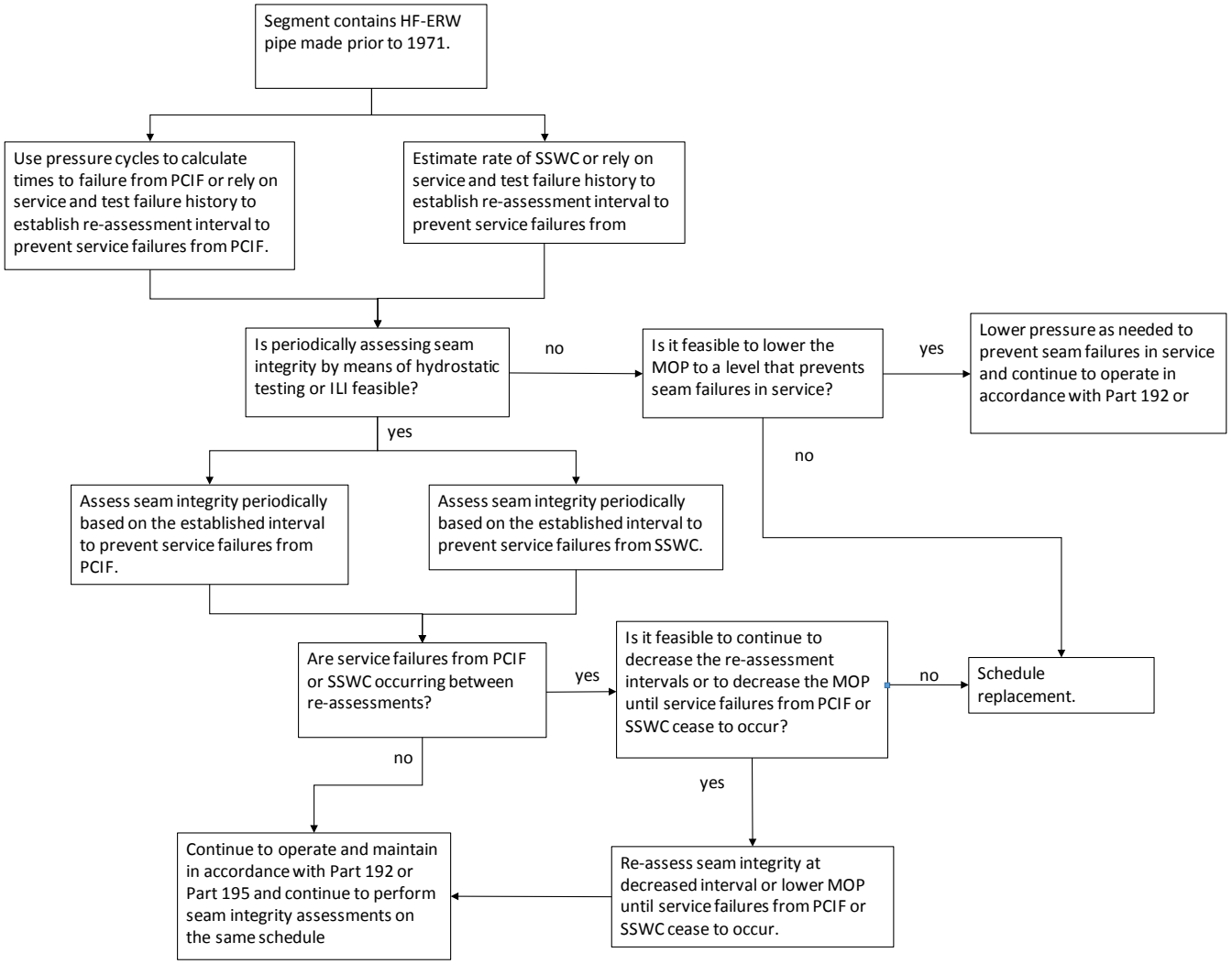


Figure C9. Flowchart HF ERW

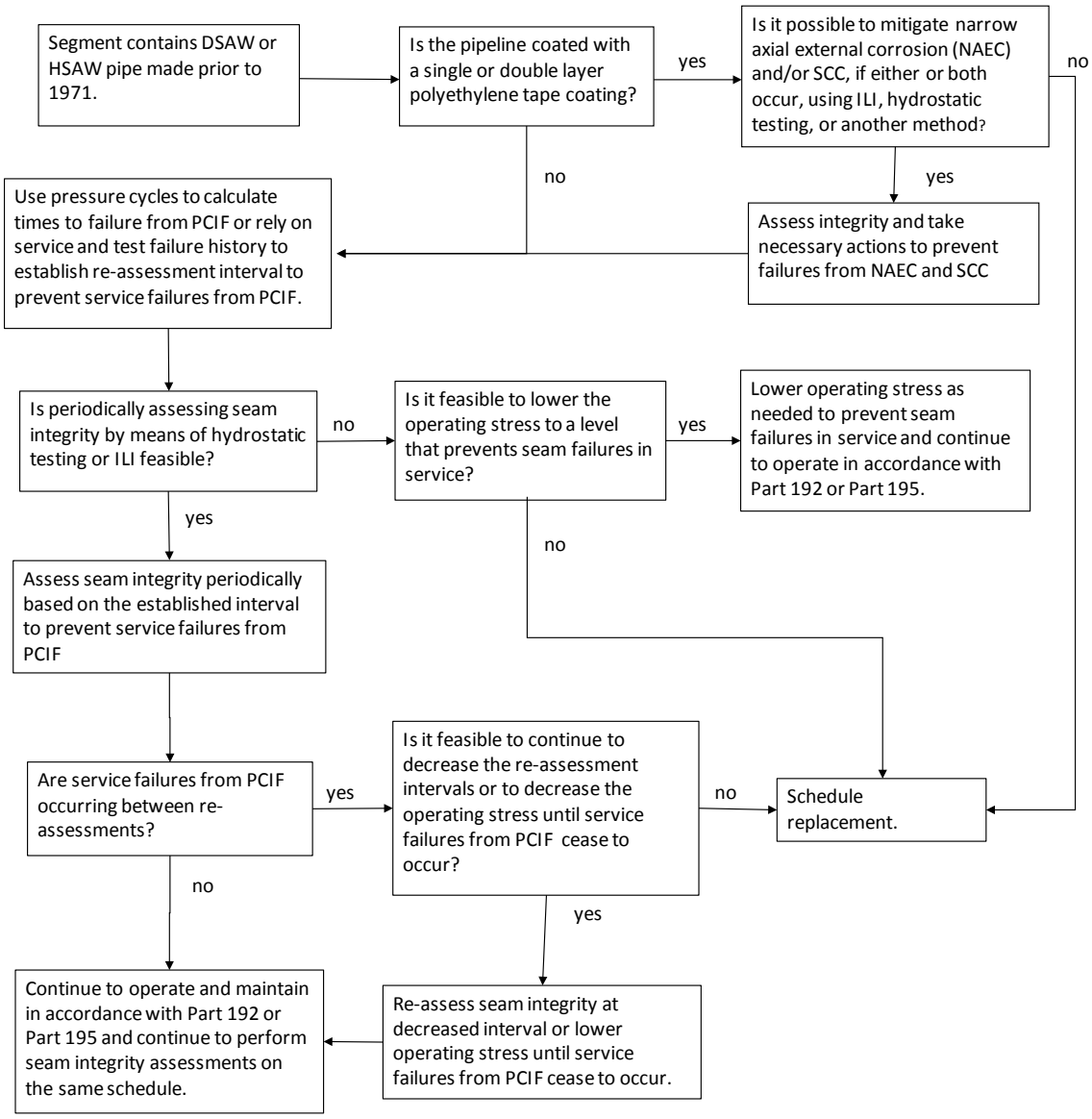


Figure C10. Flowchart DSAW

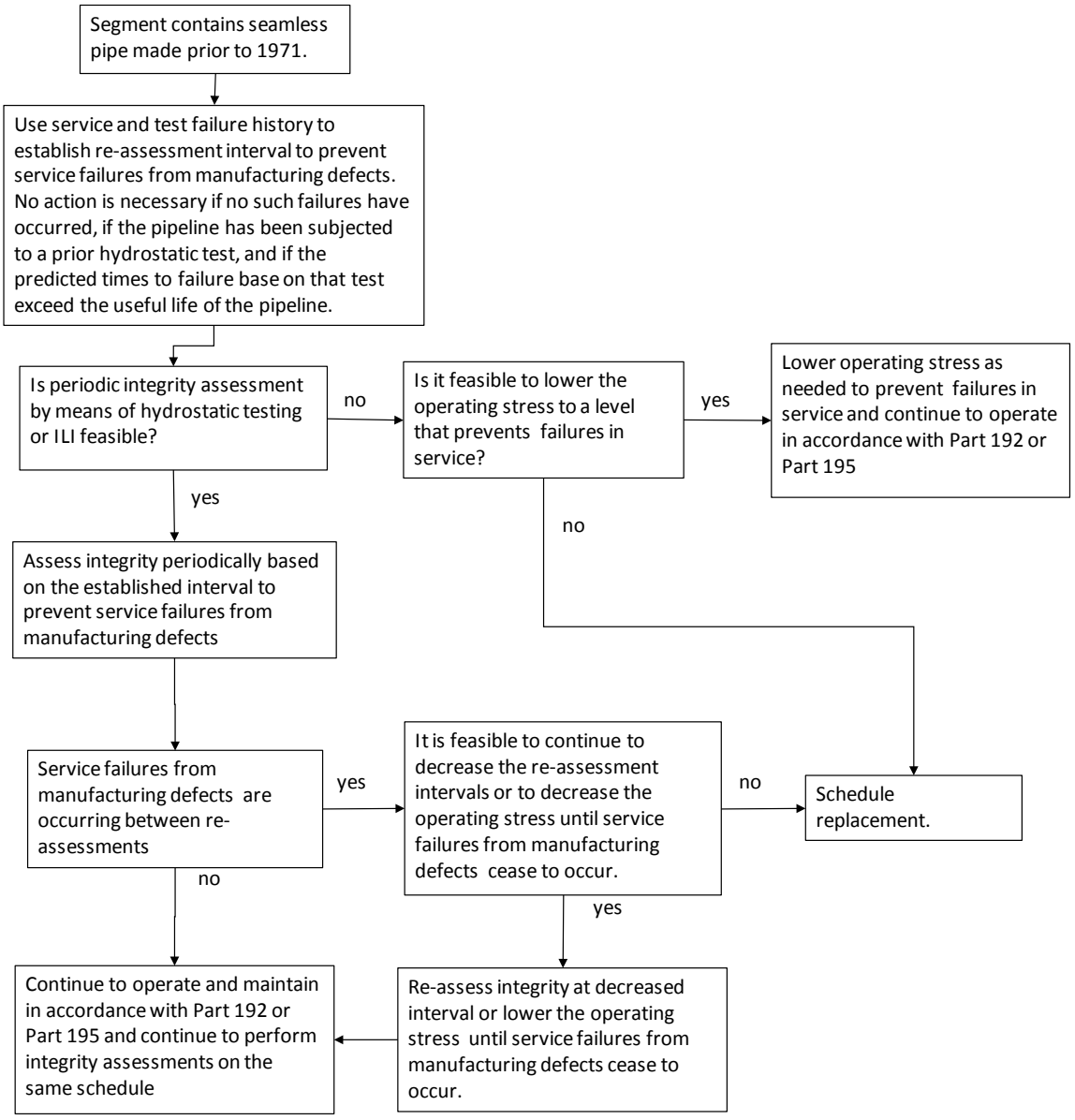


Figure C11. Flowchart SEAMLESS

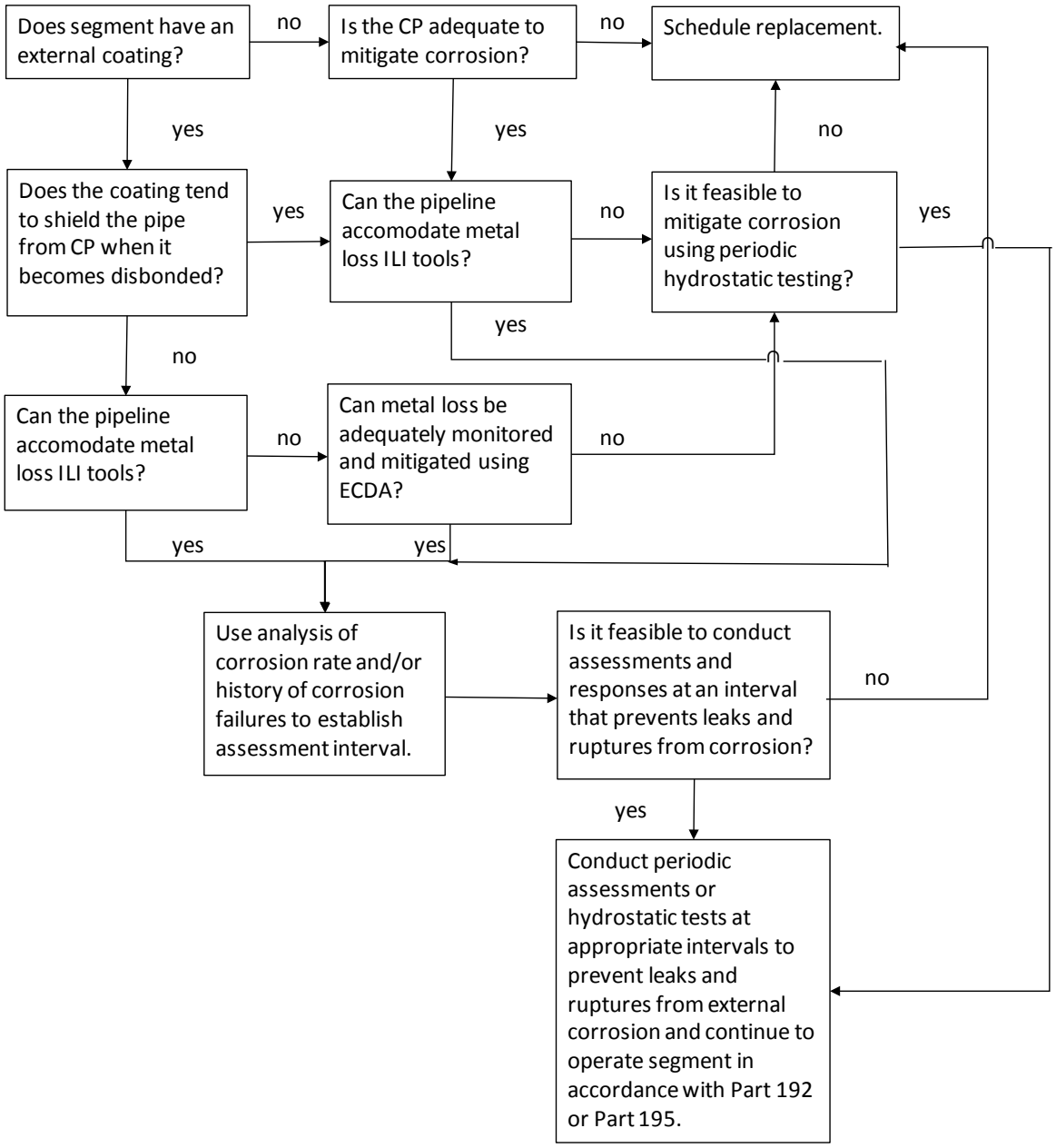


Figure C12. Flowchart EC

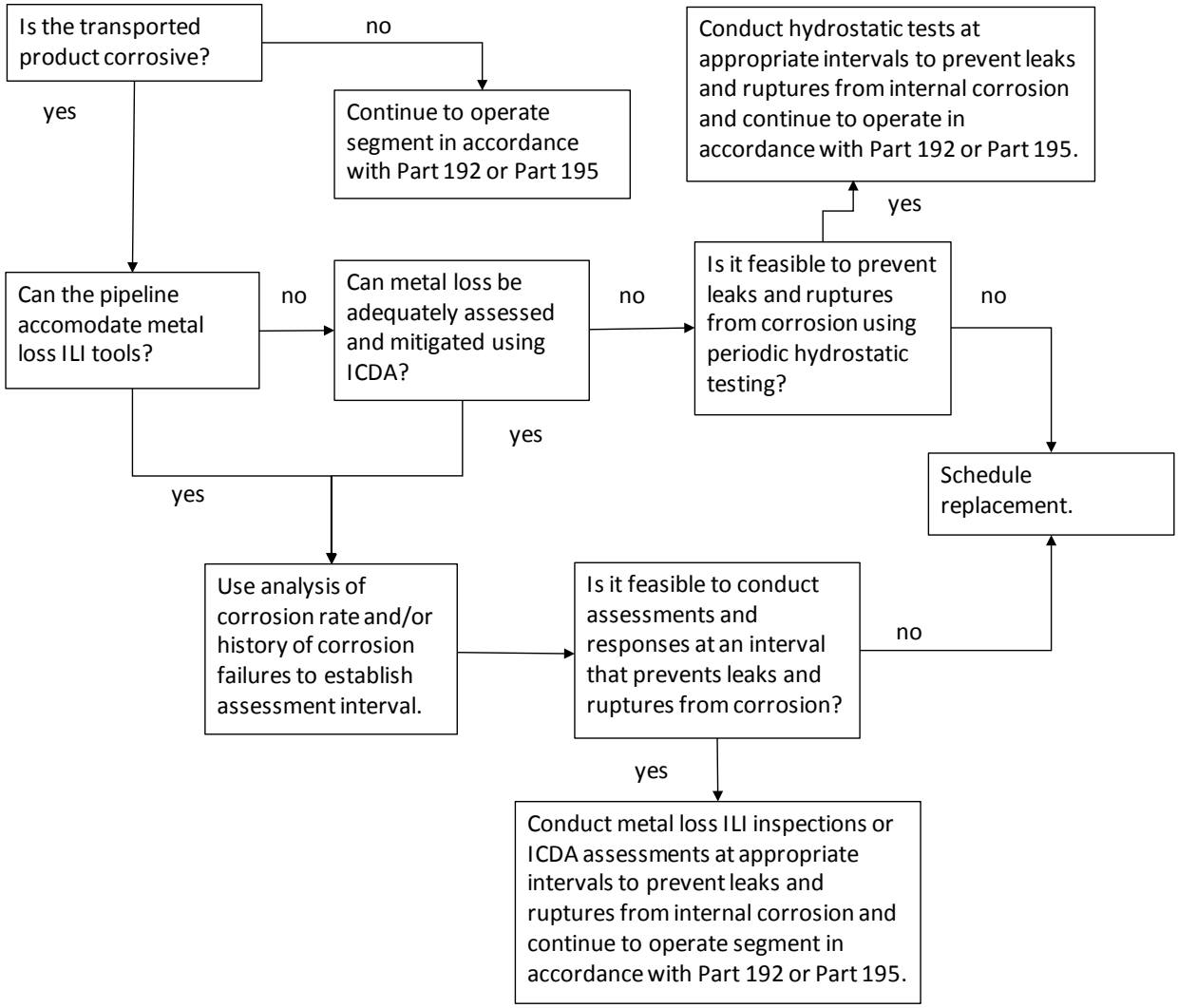


Figure C13. Flowchart IC

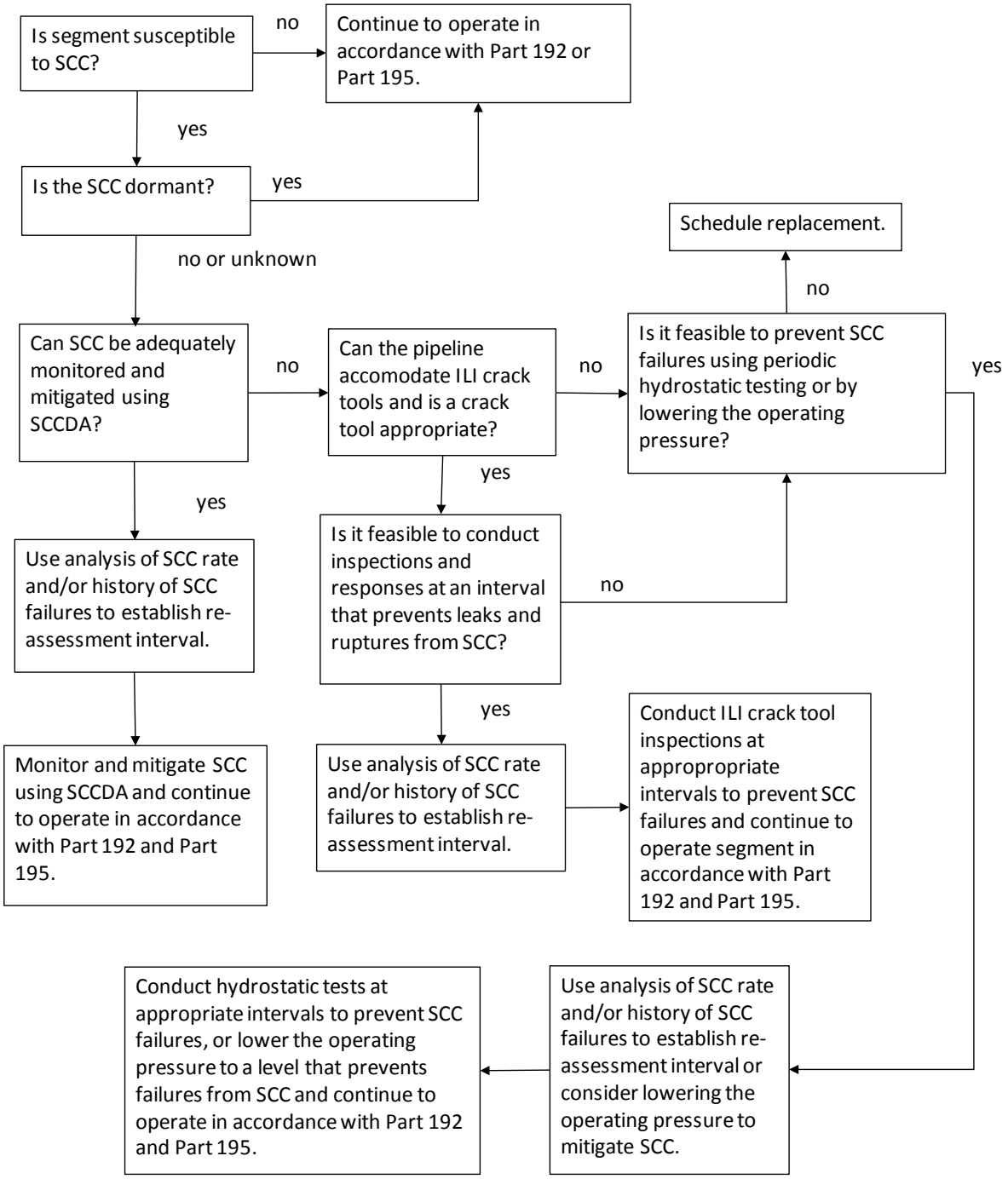


Figure C14. Flowchart SCC

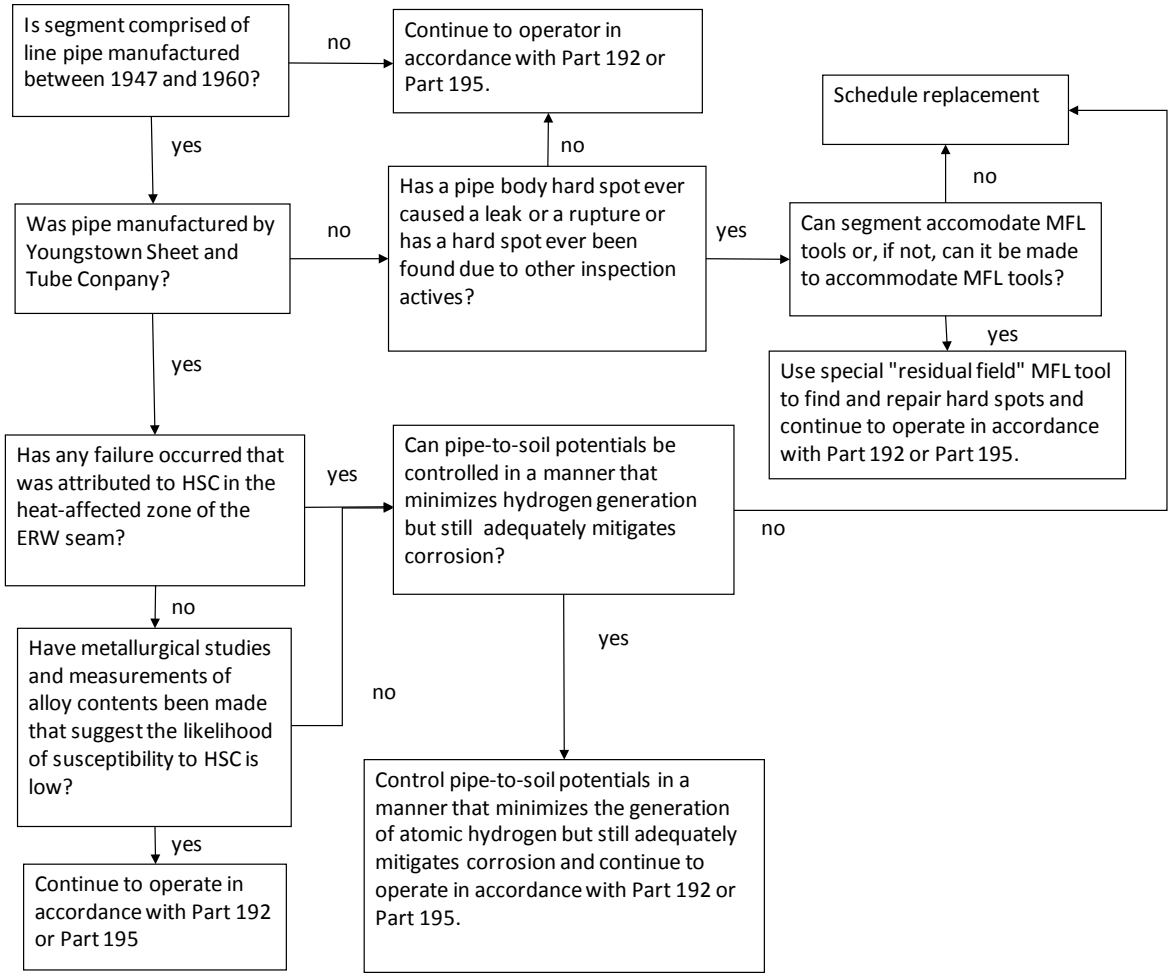


Figure C15. Flowchart HSC

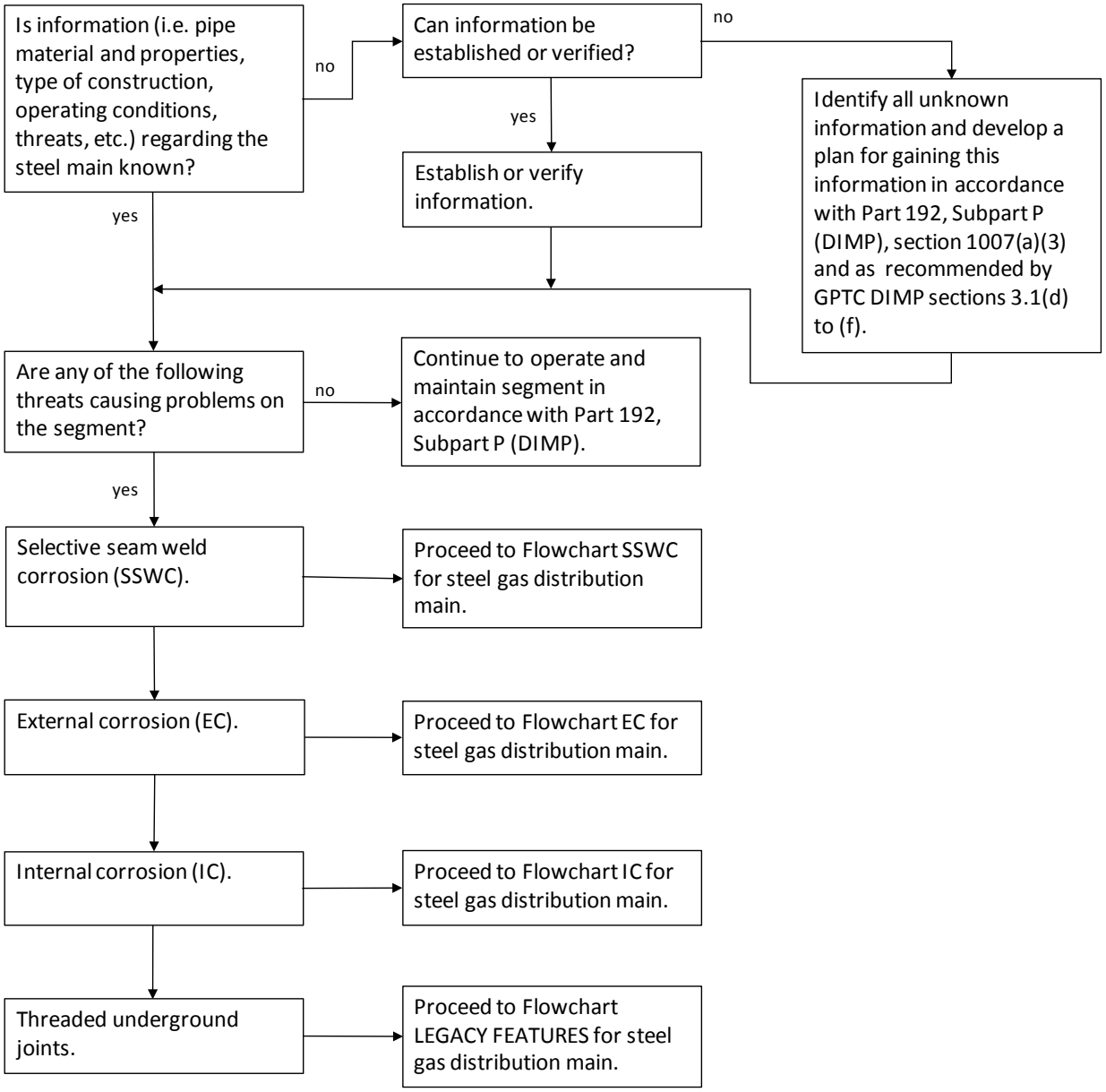


Figure C16. Flowchart START (for steel gas distribution system main)

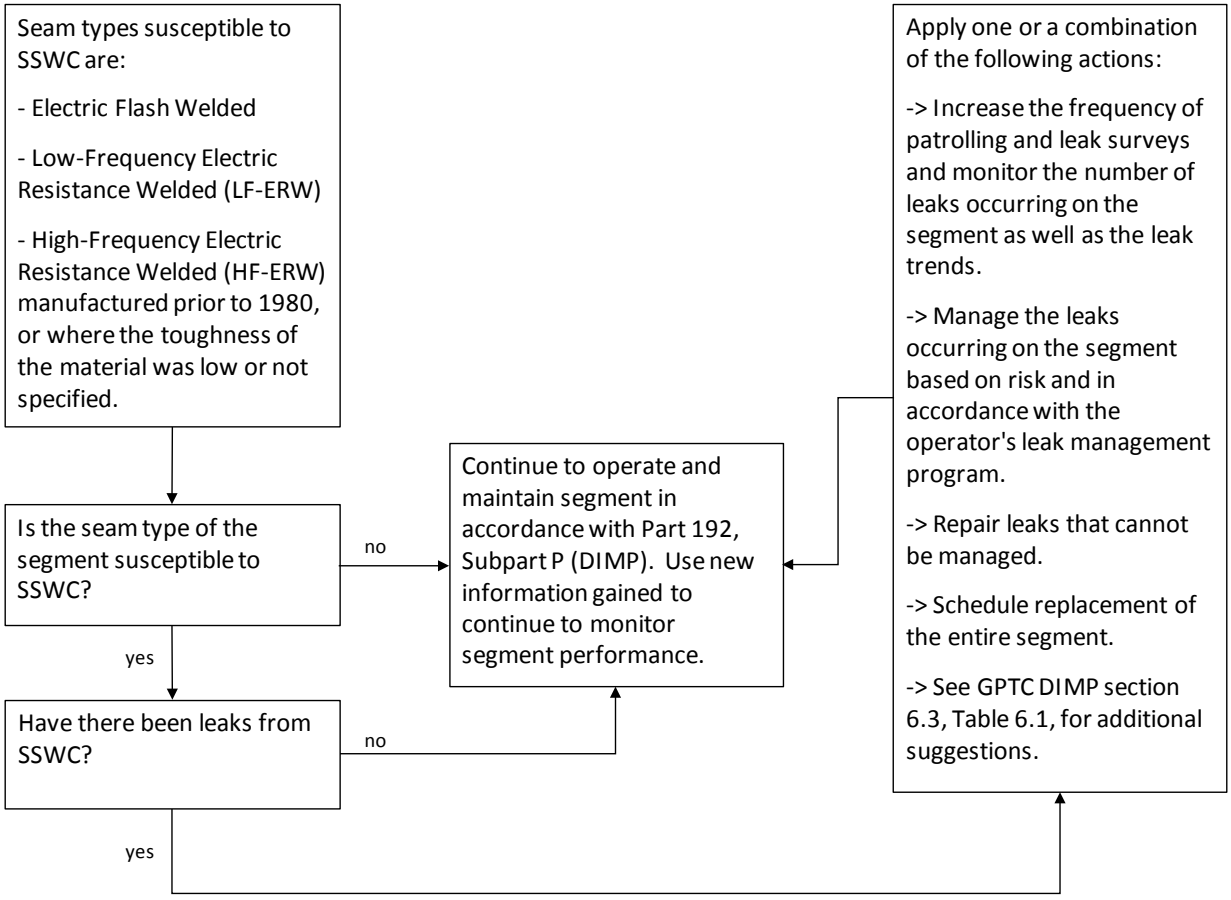


Figure C17. Flowchart SSWC (for steel gas distribution system main)

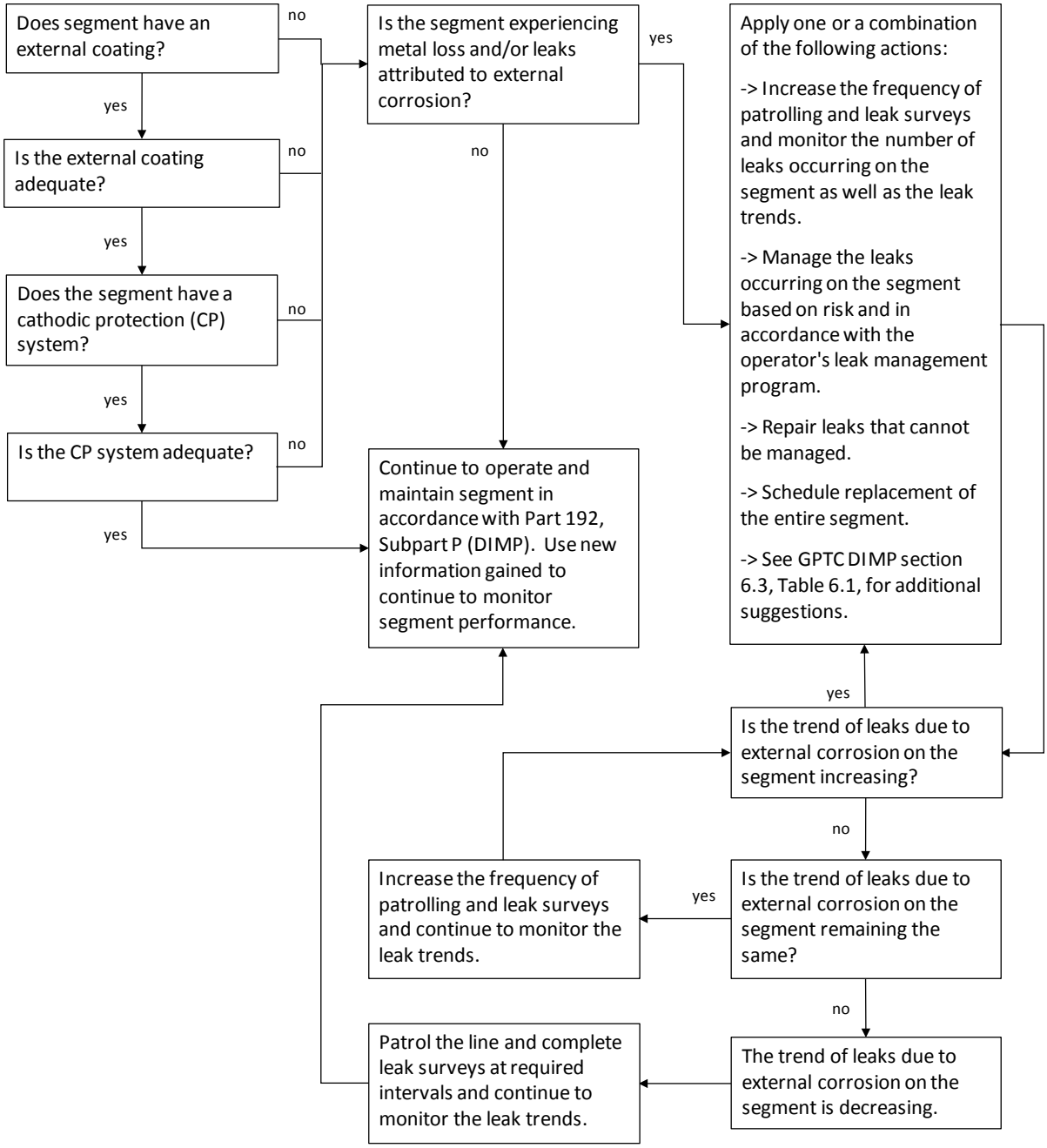


Figure C18. Flowchart EC (for steel gas distribution system main)

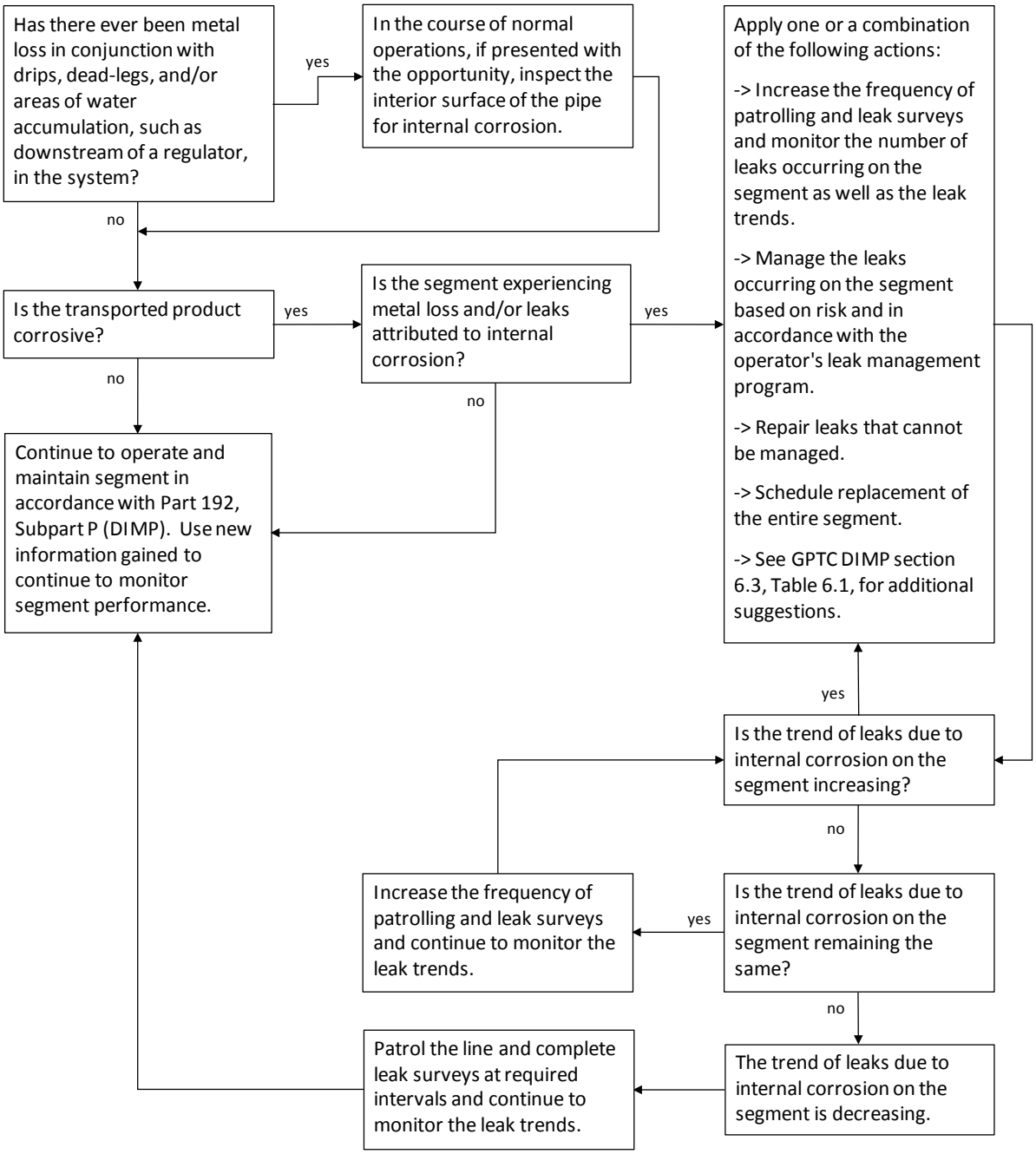


Figure C19. Flowchart IC (for steel gas distribution system main)

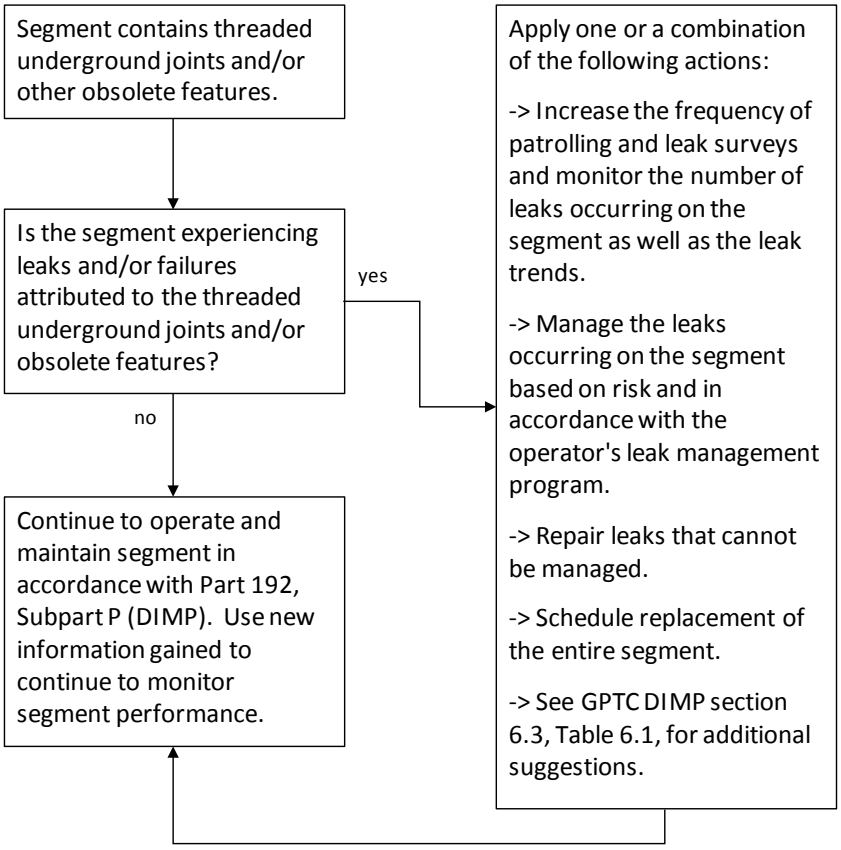


Figure C20. Flowchart LEGACY FEATURES (for steel gas distribution system main)

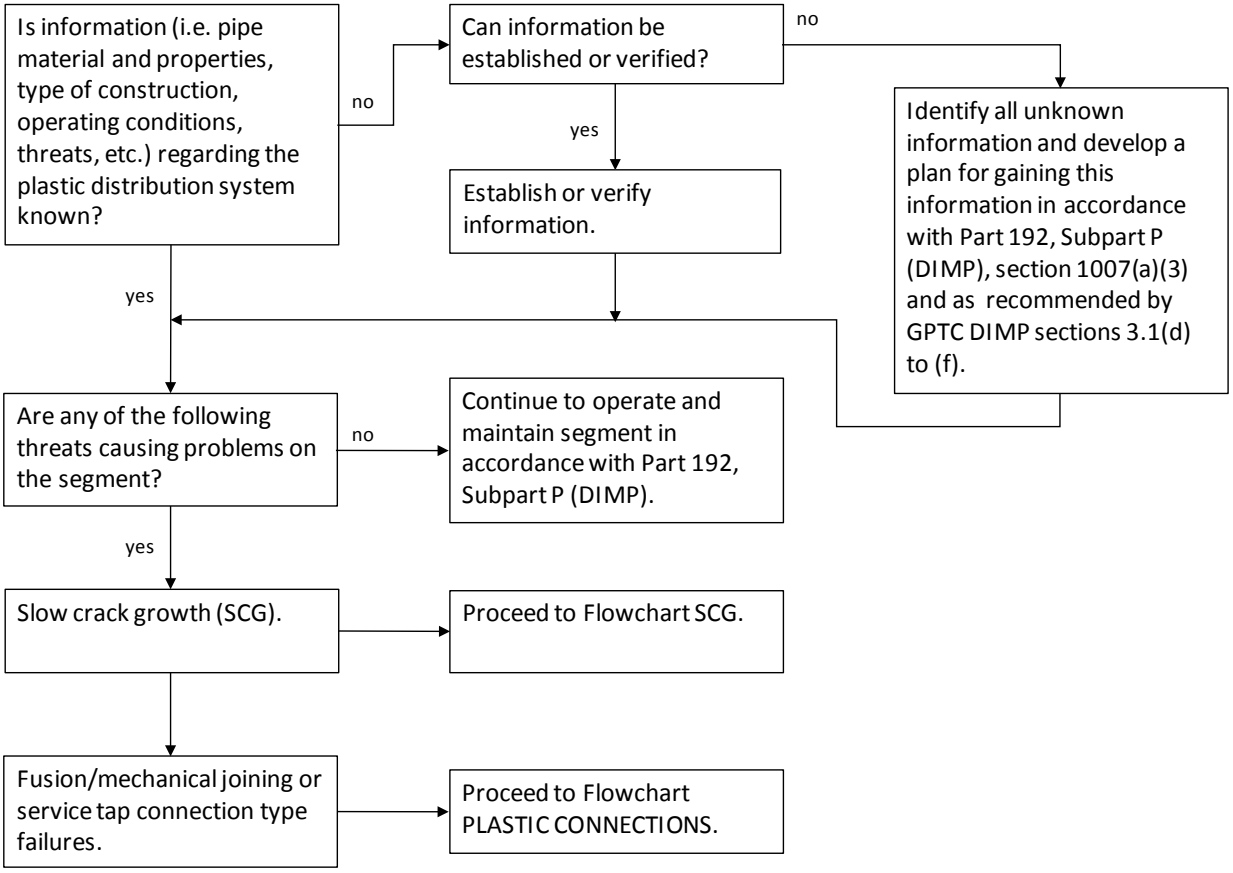


Figure C21. Flowchart START (for plastic gas distribution system)

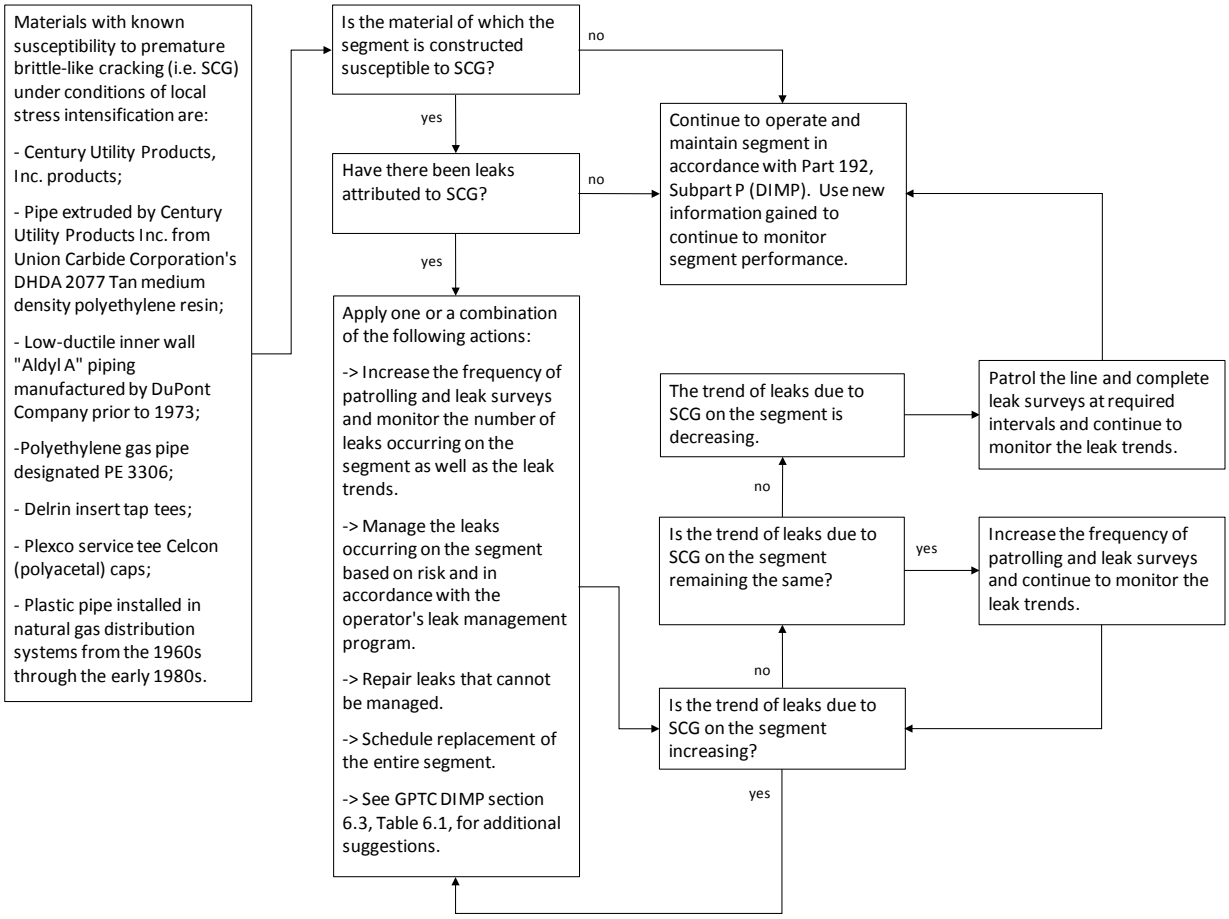


Figure C22. Flowchart SCG (for plastic gas distribution system)

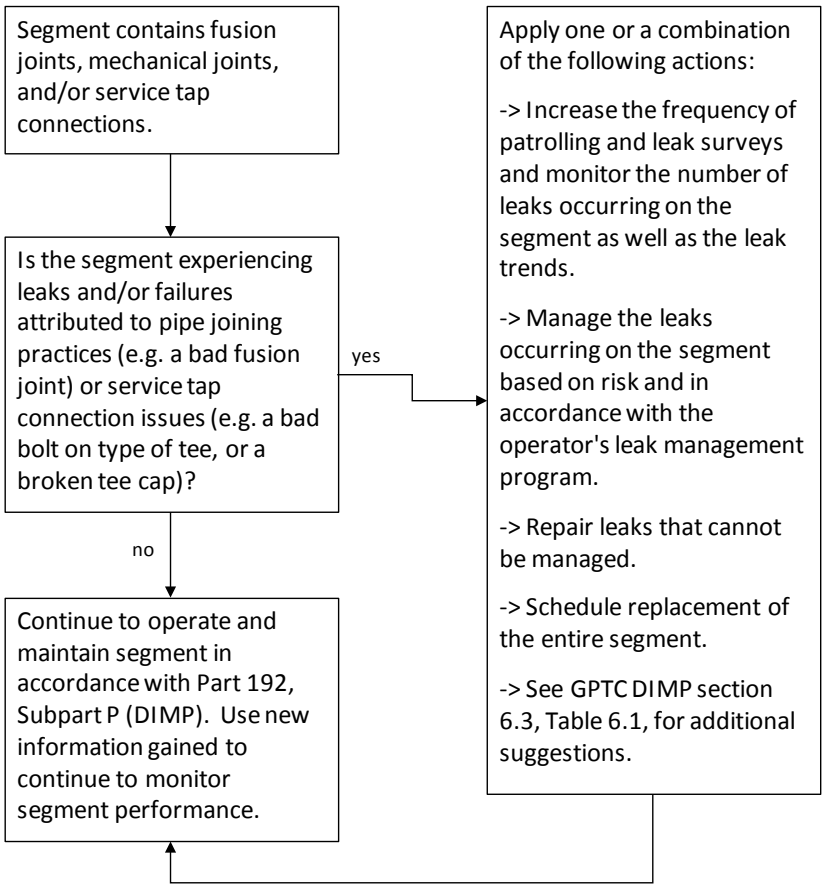


Figure C23. Flowchart PLASTIC CONNECTIONS (for plastic gas distribution system)

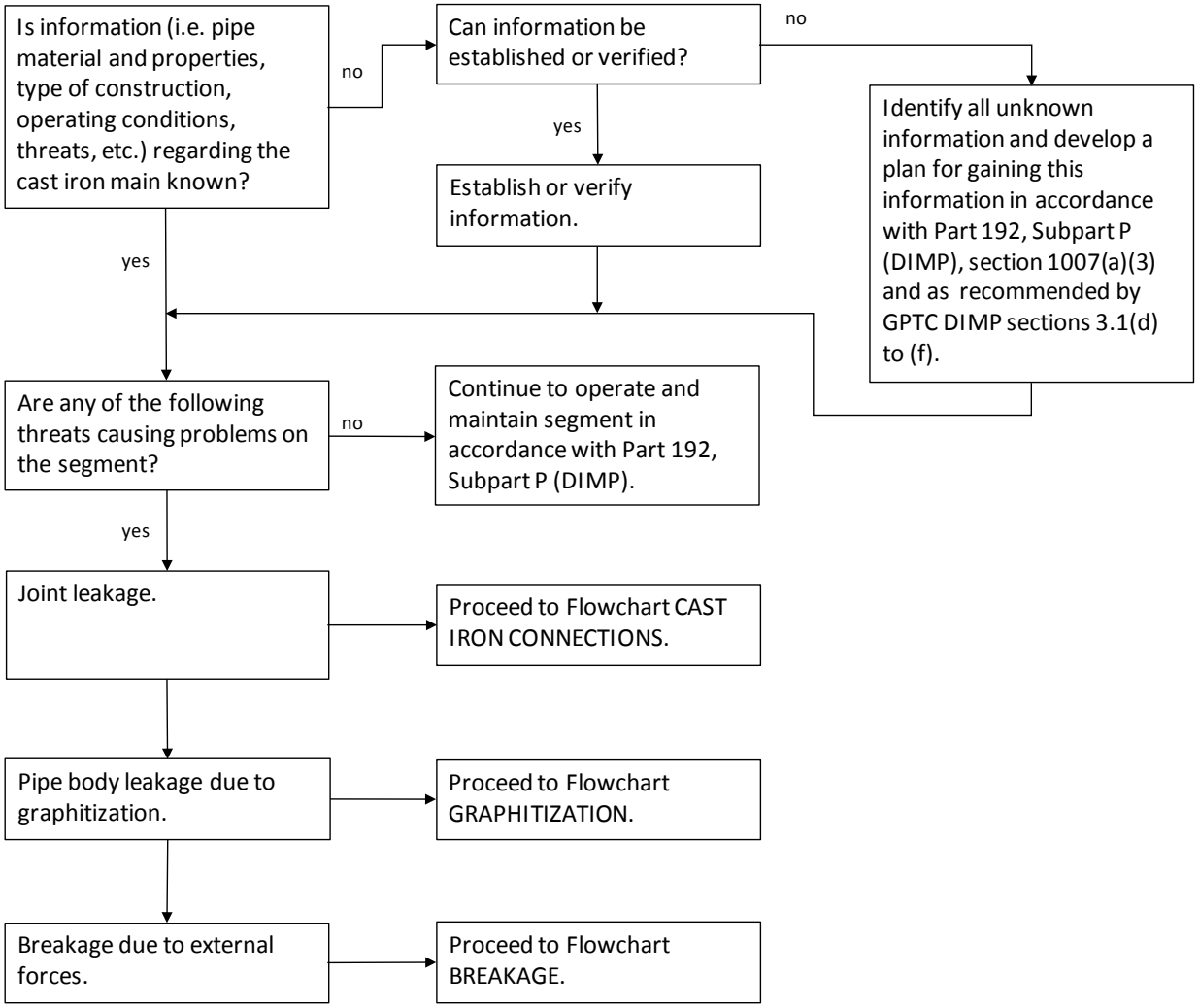


Figure C24. Flowchart START (for cast iron gas distribution system main)

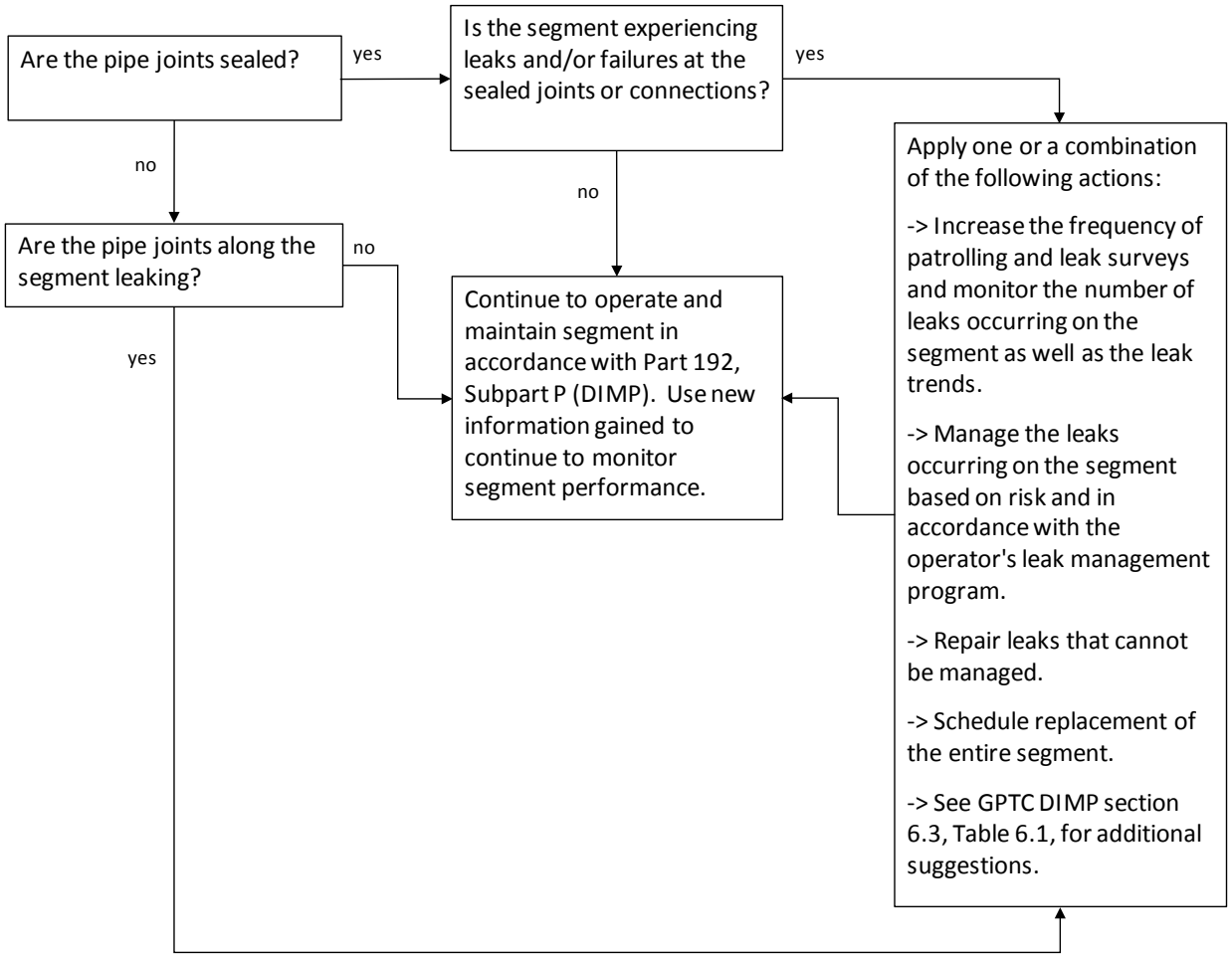


Figure C25. Flowchart CAST IRON CONNECTIONS (for cast iron gas distribution system main)

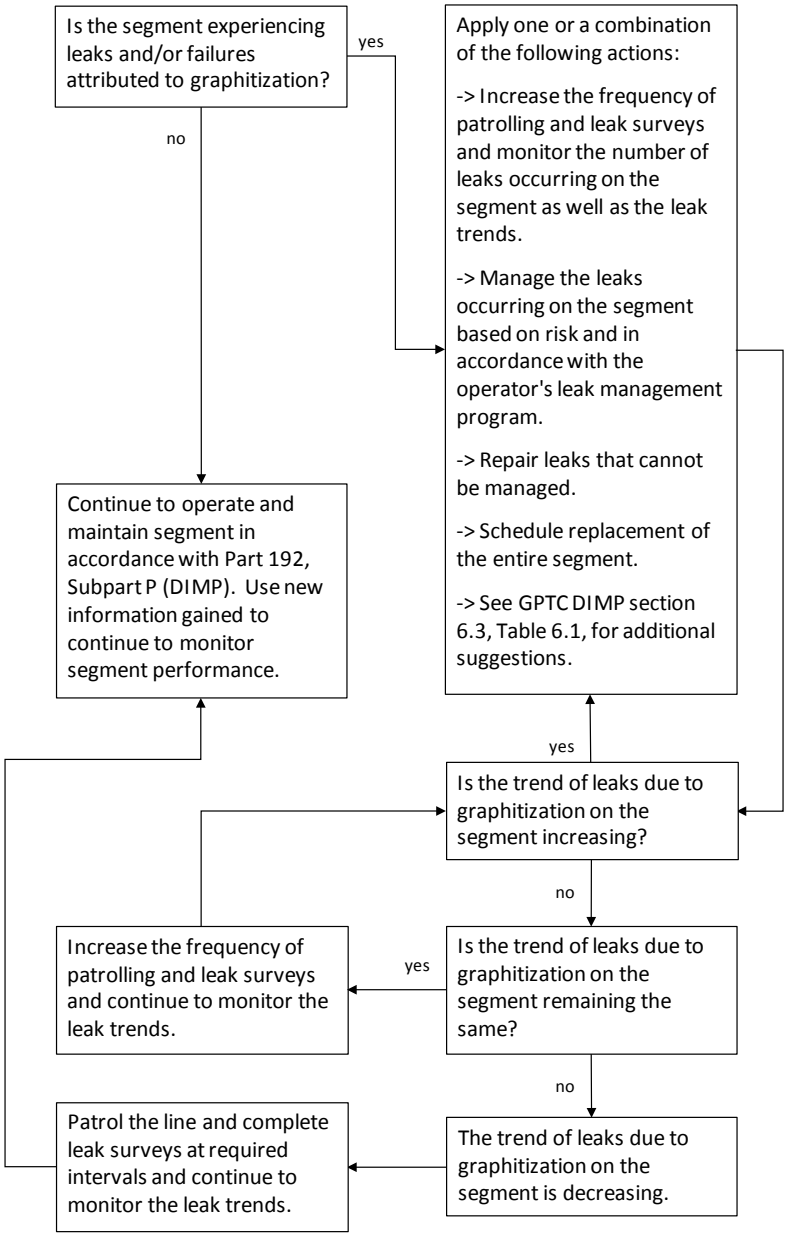


Figure C26. Flowchart GRAPHITIZATION (for cast iron gas distribution system main)

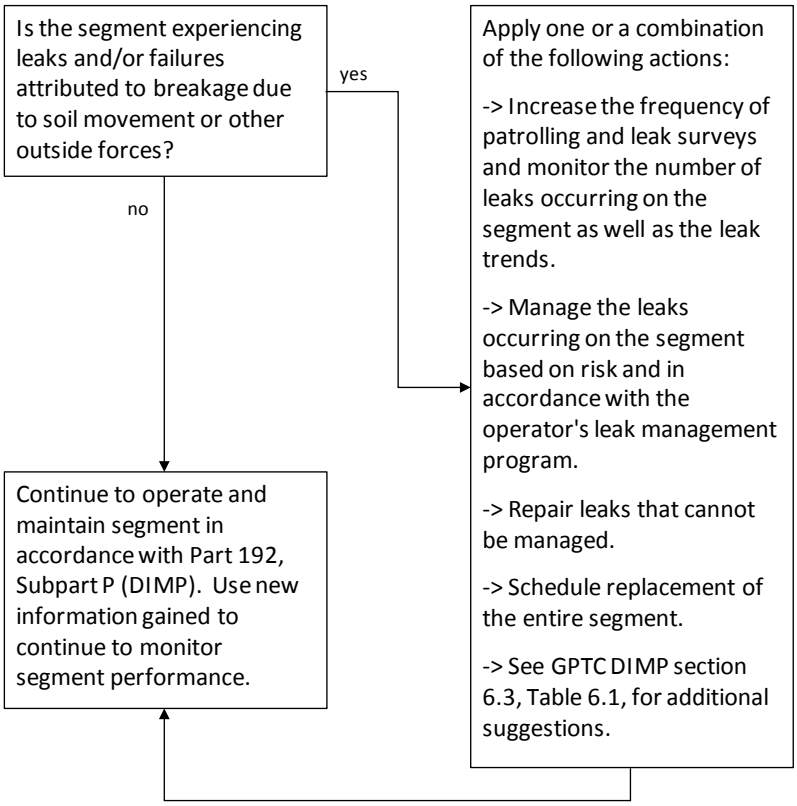


Figure C27. Flowchart BREAKAGE (for cast iron gas distribution system main)

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PPM

INFRASTRUCTURE RENEWAL SPECIALISTS

Cured-in-place Lining (CIPL) for the life extension and renewal of natural gas pipelines – Comprehensive FAQ

1. **Can lining (CIPL) rehabilitate both cast-iron and steel pipes?**

   CIPL rehabilitation can be performed on all metallic pipes, including cast iron, steel (wrapped or bare), and wrought iron. Lining does not, however, eliminate the need for cathodic protection.

2. **What happens to the exposed liner when all the bare steel corrodes away?**

   Corrosion occurs within localized "corrosion cells," which eat away at a small area of pipe until a hole forms—typically around ¼-inch in diameter. Such holes cause a gas leak and are quickly repaired. The pipe does not thin uniformly until it disappears. The exposed liner can support earth and traffic loads over corrosion holes up to 3 inches in diameter. If a steel pipe installed in the 1930s has developed only a ¼-inch hole in nearly 100 years, it would take far longer than the liner's lifespan for that to grow to 3 inches.

3. **What is the life expectancy of the liner?**

   Extensive testing conducted by **Cornell University** and **NYSEARCH** has demonstrated an **expected service life exceeding 100 years**. Axial, rotational, expansion, and contraction testing—totaling over two million cycles, was performed under the supervision of major utilities including National Grid, Con Edison, and PSEG.

   Starline® CIPL has undergone more than **$15 million in independent testing** across multiple facilities. These results confirm that the bonded liner maintains its structural and pressure integrity over a century-long design horizon. Full testing data and reports are available upon request.

4. **Can lining traverse bends, and if so, how many?**

   Yes. Lining through bends is routine. The number of bends that can be lined depends on the pipe's geometry and diameter. Mitered bends present additional challenges, which are evaluated before each project begins.

5. **What is the maximum length of liner able to be installed per inversion?**

   - **4–10 inches diameter:** up to 800 ft
   - **12–24 inches diameter:** up to 1,200 ft
   - **> 24 inches diameter:** up to 800 ft

   Segments containing multiple bends are individually analyzed during project design.

6. **What pipe diameters and pressures can lining accommodate?**

   Lining can be installed in metallic pipes from 2 to 48 inches in diameter. Starline® CIPL has been tested to withstand pressures up to a **maximum allowable operating pressure (MAOP) of 450 psig**.

7. **How long does it take for the liner to cure?**

   Conventional adhesive cure time depends on ambient and ground temperature, typically about 24 hours, or up to 48 hours in cooler conditions. Accelerated curing methods using forced hot air or ultraviolet light are being field-tested and are expected to be commercially available in 2026. These methods can complete the full lining process within **8–12 hours**.

8. **How are service connections handled?**

   During curing, connected gas services are temporarily out of service. After curing, services are **robotically reopened from inside the main** without external excavation. Future systems using UV- or hot-air-activated resin will shorten the overall outage period.

9. **Can gas migrate between the liner and host pipe?**

   No. Gas migration, sometimes called "tracking," does not occur because the liner is chemically bonded to the host pipe, preventing any path for gas movement.

10. Can a lined segment of pipe be cut in the future?

Yes, using a **toothed cutting blade** such as a high-speed reciprocating saw. Snap-cutting will not work because the liner resists the fracture, and a punch-out method may jeopardize the liner bond prematurely. All cuts in steel or cast-iron pipe must use a toothed blade.

11. How is gas "stopped off" on a lined segment of pipe?

Gas stopping is performed exactly as on unlined pipe. No special procedures or tooling are required.

12. Can a new gas service be added to a lined pipe?

Yes. Service installations or tap cuts are performed as usual, but the **shell cutter must have teeth** to avoid damaging the liner, and a **high-speed drill** should be used instead of a punch-out device.

13. Can welding be performed on a lined pipeline?

Yes, but only with the appropriate precautions. All welding, including service connections and anode attachments, must be performed **while the pipeline is energized (gassed-in)** so that no oxygen is present to support combustion. Welding on a non-energized lined pipe can burn or damage the liner. Whenever possible, welding should occur **before** lining.

14. What determines the pit size required for lining?

Pit dimensions depend on pipe geometry, diameter, and depth. A reference chart can be provided upon request to guide pit sizing.

15. Do all unwanted valves need to be removed?

Not all.

- Open **plug** or **butterfly** valves must be removed.
- Open **gate** valves can be lined through but will cause a small internal protrusion, reducing flow by about 20 percent.
- **Ball** valves can be lined through without issue. Any valve that has been lined can no longer function as an operational valve.

16. Do unwanted drip pots need to be removed?

No. Robotic cutters remove the standpipe, and a **carbon-fiber sleeve** is installed across the cavity. The liner then bridges over the drip-pot opening, restoring full integrity without removal.

17. How is heavy corrosion or a leak within a bridge abutment wall handled?

After internal cleaning, a **carbon-fiber Structural Reinforcement Sleeve (SRS)** is robotically installed at the defect. The SRS is twice as strong as steel and restores pipe integrity. The segment is then lined, sealing in the SRS and fully rehabilitating the pipe.

18. How is a wet pipeline containing water or oils handled?

Water and oil are handled separately:

- **Water:** removed through foam-pigging and vacuum drying. All liquids are collected and tested as required (e.g., PCBs) for utility-controlled disposal.
- **Oil:** removed by high-pressure water-jetting with solvent, then collected for disposal. Drying follows the same procedure used for water removal.

19. How is infiltrating water handled?

Slow infiltration is sealed with a **robotically installed patch**, cured for 1–2 hours. After curing, the pipeline is dried and lined using the standard process.

20. Does the liner absorb mercaptan?

All new installation materials, including steel and polyethylene initially absorb small amounts of odorant. Because the liner's polyethylene skin is very thin, it absorbs only a minimal quantity, allowing rapid "pickling." The absorbed mercaptan quickly dissipates.

21. How does CIPL comply with PHMSA and state pressure-testing requirements?

CIPL has been independently verified through **PHMSA and ASTM testing** to maintain pressure integrity far above regulatory thresholds. While cast-iron and low-pressure systems are commonly tested at 1.5 × MAOP (≈ 37.5 psig for 25 psig systems), Starline® CIPL has demonstrated safe operation at pressures exceeding 450 psig. Each installation follows the utility's approved testing protocol in compliance with **49 CFR Part 192** and applicable state DPU standards.

22. How do regulators classify CIPL—repair, rehabilitation, or replacement?

Both **PHMSA** and **ASTM F2207** classify CIPL as a **repair / rehabilitation** technology, not a replacement. Accordingly, the lined segment retains its original MAOP and should not be uprated. CIPL is intended for leak-prone, low- or intermediate-pressure pipelines where full replacement is impractical and or cost-prohibitive.

23. What Operator Qualification (OQ) standards apply to CIPL installation?

CIPL tasks are covered under existing OQ frameworks. The **Mid-Atlantic Energy Association (MEA)** established **Task 1031: Install or Repair Internal Liner**, encompassing cleaning, surface preparation, installation, adhesion verification, inspection, and documentation. PPM supplies task outlines and training materials for integration into operator OQ and O&M programs.

24. How independent is the liner from the host pipe's condition?

Tests by **Cornell University** with funding from **PHMSA** several utility companies confirm that CIPL retains full pressure integrity even after major host-pipe degradation. Lined segments withstand corrosion holes up to 6 inches and circumferential gaps up to 3 inches without failure. The bonded structure forms a **Class II composite pipeline**—a unified pressure vessel of liner + host pipe.

25. How much does it cost to line a natural gas main, including all PPM costs for materials and installation?

The table below provides **2025 per-foot pricing estimates** for lined pipe by diameter. Actual costs may vary based on factors such as tariffs, transportation fluctuations, job location, project length, order volume, and site-specific requirements (e.g., work windows and traffic control stipulations).

This pricing reflects **PPM's total estimated price for Starline® CIPL materials (manufactured in Germany) and installation. PPM collaborates with each client to** optimize project design and achieve the **lowest possible delivered price once all project details are known**.

Starline CIPL Installed Price Estimate	
Diameter	Total Price Per Foot
4"	$276.14
8"	$333.50
10"	$356.37
12"	$397.94
16"	$459.99
20"	$515.82
24"	$617.97
30"	$808.16
36"	$945.34
40"	$1,062.27
42"	$1,122.80
48"	$1,235.08

26. How does CIPL affect system up-rating capability?

While **up-rating of CIPL-lined segments is currently prohibited** under existing PHMSA regulations because CIPL is classified as a **rehabilitation method**, recent **CIPL Pressure Integrity testing** and the **inherent performance of Class II composite liners** indicate that up-rating is technically feasible.

Independent third-party testing to **ASTM standards** has shown that the **burst pressures of the liner alone far exceed the rated operating pressures** of both the liner and the resulting composite pipe by **an order of magnitude**. This provides a significant margin of safety and demonstrates the liner's ability to withstand higher operating pressures than those currently permitted.

Additional testing is underway to further define the **precise pressure range capabilities** of the CIPL system. These results may help inform future discussions around regulatory pathways for **potential up-rating of CIPL-rehabilitated assets**, particularly in segments where structural enhancement and pressure containment have been conclusively validated.

27. What are typical customer outage durations?

Ambient-cure installations generally require 24 hours from isolation to service reinstatement.

Accelerated curing with UV, forced hot air or hot-water activation reduces total lining operation to **8–12 hours**.

28. How are connections made between lined and unlined pipe sections?

Each segment ends with a **steel or polyethylene spool piece** bridging to the next section. Connections use compression couplings or fusion welds with cathodic protection as required. Properly installed and tested, these joints are as reliable as any standard pipeline connection.

29. What are the best use cases for CIPL?

CIPL is most effective for:

- Bridge, river, and highway crossings
- Dense urban or access-restricted areas
- Large-diameter mains (12–48 in.) where throughput cannot be reduced.
- High-restoration-cost zones (curb-to-curb paving)
- Pipelines near critical infrastructure such as schools, hospitals, and rail lines

CIPL is a versatile rehabilitation solution effective across a wide range of pipeline sizes and conditions.

While large-diameter mains (12–48 in.) are traditional candidates due to their high restoration and access costs, **small-diameter pipelines (2–12 in.) are increasingly ideal** when located in:

- High-cost restoration zones (urban streets, historic districts, or areas requiring full curb-to-curb paving)
- Locations where excavation is impossible or severely constrained (beneath highways, rail crossings, bridges, or dense utilities)
- Projects where speed of installation and minimal customer disruption are critical.

Recent advances in **temporary gas-supply and bypass methods**, combined with **emerging accelerated-curing systems**, are making small-diameter lining with active service connections significantly more feasible than in the past. Overall, CIPL delivers maximum operational and economic benefit where excavation is limited; surface disruption must be minimized, or rapid restoration is required.

30. How does CIPL support methane emission and environmental compliance?

CIPL seals all joints, leaks, and porosity, eliminating gas migration and methane emissions. Its trenchless nature reduces surface excavation, traffic impacts, and restoration emissions. The technology aligns with **PHMSA and EPA** methane-reduction goals and qualifies for inclusion in leak-prone-pipe or emission-mitigation programs.

31. How do CIPL costs compare with traditional replacement?

CIPL typically saves **30–60 percent** overall in urban, high-restoration, or access-limited areas by avoiding paving, traffic control, and restoration expenses. Furthermore, CIPL eliminates leaks and prevents future methane emissions even in the event of host pipe failure.

32. Has CIPL been validated by third parties?

Yes. Independent and federally sponsored studies confirm their safety and durability, including:

- **PHMSA "100-Year Test" (Project #502)** – cyclic-loading validation
- **NYSEARCH & Cornell University** pressure and fatigue testing
- **ASTM F2207-02 and F2207-06** certification (to 300 psi)
- **Ongoing 2025** testing confirming pressure integrity and containment after host-pipe failure.

33. Can utilities capitalize CIPL rehabilitation projects?

Yes. Many utilities classify CIPL as a **capital improvement** under infrastructure-renewal or leak-prone-pipe programs. Capitalization eligibility follows each operator's accounting policy and DPU precedent.

34. How does CIPL interact with cathodic-protection systems?

CIPL isolates only the internal wall and does not alter external cathodic-protection requirements. Standard anode or impressed-current systems remain compatible. Any new steel spool pieces are protected with sacrificial anodes or bonding per operator practice.

35. Is CIPL a structural solution?

Yes. Cured-in-place Lining (CIPL) provides **structural enhancement to the host pipe**, transforming the lined section into a **composite pressure vessel** that combines the strength of both materials.

Extensive testing by **Cornell University**, **NYSEARCH**, and **more recent CIPL Pressure Integrity studies** demonstrates that the liner maintains internal pressure even **after the host pipe has failed**. These tests confirm that CIPL sustains full pressure containment when the host pipe exhibits severe corrosion, perforations, or complete circumferential or longitudinal defects, conditions that would otherwise result in failure.

CIPL is classified as a **Class II structural liner**, meaning it is bonded to and reinforces the host pipe to restore its structural and pressure integrity. This class is intentionally selected over **Class IV (fully structural, stand-alone) liners** to **prevent gas tracking** between the liner and host pipe—a critical consideration for pressure applications.

In gas distribution systems, where the transported material itself poses significant risk if uncontained, this bonded Class II configuration offers superior safety by ensuring no pathway for gas migration. Additionally, the **thinner profile** of a Class II liner is well suited to natural gas distribution mains, allowing **longer installation runs**, **traversal of multiple bends**, and **maintenance**, **or even improvement**, **of flow capacity**.

36. How do CIPL-lined pipes perform in the event of third-party damage or soil movement?

Unlike rigid host materials such as cast iron or steel, **CIPL creates a flexible composite pipe** with a more favorable failure mechanism under stress. Extensive **CIPL Pressure Integrity testing** has demonstrated that the bonded liner can **maintain pressure containment even after the host pipe** has failed due to circumferential breaks, longitudinal cracks, or complete section loss.

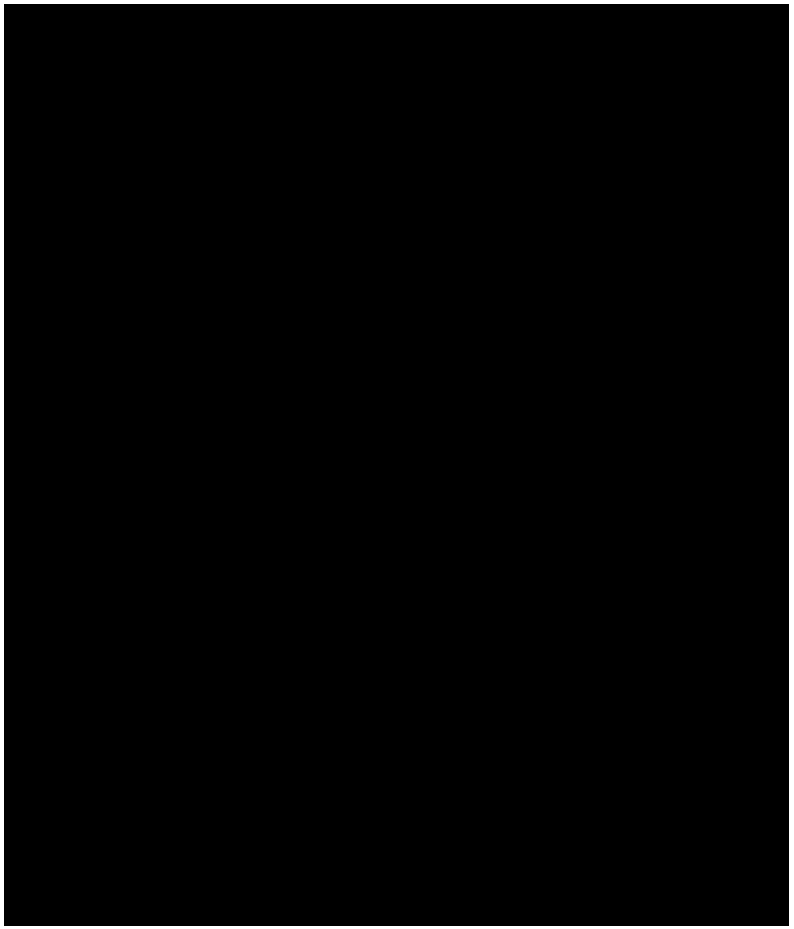
In scenarios such as a **backhoe strike**, **undermining soil from a water main break**, or other third-party impacts, the liner remains **intact and pressurized**, acting as a **composite pressure vessel** rather than a brittle structure. The liner is engineered to **absorb and redistribute strain by intentionally dis-bonding at controlled levels**, a behavior governed by the **specific resin bond strength requirements in ASTM F2207**. This controlled dis-bonding allows the liner to flex and relieve stress without losing pressure containment.

This resilience represents a key safety advantage of CIPL over traditional rigid materials, ensuring system integrity even under severe, unplanned external loading or ground movement.

37. What additional costs are typically incurred outside of PPM's scope?

In addition to PPM's lining and material costs, typical project expenses may include:

- **Test pits:** Excavation to locate utilities, confirm depths, and assess spatial constraints.
- **Lining pits:** Send/receive pit excavation sized to depth and main diameter (e.g., ~8'W × 15'L).
- **Gas main shutdown:** Hot taps, stopple fittings, stopping-off, and purge.
- **Post-lining gas-in:** O_2 purge, stopper removal, and completion plugs.
- **Tie-ins:** Spool piece fabrication and installation.
- **Pressure testing:** Per utility specifications.
- **Backfill and restoration:** Per DOT or municipal requirements.



Source: PHMSA. "Gas Distribution Incident Data – January 2010 to present." Accessed March 16, 2026. https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data

Report Number	20260005
Incident date	January 5, 2026
City	Ashburn
County	Loudoun County
State	VA
System part	Main
Installation year	2023
Material	Plastic
Cause	Excavation Damage by Third Party
Root cause or outside force type	Ticket was coded 90, which means no access. Contractor continued to excavate on the Code 90 ticket. In Virginia, Code 90 ticket requires the excavator to call and request another ticket, this excavator did not request a new ticket.
Fatalities	0
Injuries	0
Ignition	No
Explosion	No
Narrative	On January 5, 2026, at approximately 10:53, Geothermal Technical, an excavator using a 6î auger, struck an 8" main located at Pacific Blvd and Waxpool Road, Ashburn, Virginia. Washington Gas was notified at 10:53 via the third-party excavator of the damage. The resulting damage, which was a mechanical puncture of the main, caused a gas leak. The first Washington Gas crew arrived at 11:24. The fire department notified Washington Gas they evacuated 10 businesses in the shopping center out of precaution. Washington Gas stopped the flow of gas by squeezing off the main at 04:30 on January 6, 2026. Crews have restored gas service to the area. There were no injuries from this incident.

Report number	20250024
Incident date	March 6, 2025
City	Chantilly
County	Fairfax
State	VA
System part	Main
Installation year	1998
Material	Plastic
Cause	Excavation Damage by Third Party

Root cause or outside force type	Facility Marked Inaccurately Due To Locator Error
Fatalities	0
Injuries	0
Ignition	No
Explosion	No
Narrative	On March 6, 2025, at approximately 14:15, RP Construction struck a 4-inch plastic gas main using a directional drill at the intersection of Centreville Road and Skyhawk Drive in Chantilly, VA. Washington Gas was promptly notified of the incident at 14:17 via fireboard. The impact resulted in a punctured plastic main, causing a gas leak. Washington Gas personnel arrived on-site at 15:13 and successfully stopped the gas flow at 19:29 by squeeze, which led to an outage affecting 28 customers. Service was restored to all impacted customers.

Report number	20240058
Incident date	October 15, 2024
City	Haymarket
County	Prince William
State	VA
System part	Main
Installation year	2000
Material	Plastic
Cause	Excavation Damage by Third Party
Root cause or outside force type	Improper Excavation Practice Not Listed Above
Fatalities	0
Injuries	0
Ignition	Yes
Explosion	Yes
Narrative	On October 15, 2024, at approximately 1617, Blankenship Utilities, a contractor directionally drilling a water line, struck a 2" main located at 5992 Colby Hunt Court, Haymarket Virginia. Washington Gas was notified at 1632 via fireboard of the third-party damage. The resulting damage, which was a mechanical puncture of the main, caused a gas leak. The first Washington Gas crew arrived at 1714. Subsequently, gas migrated into the house located at 5992 Colby Hunt Court, found an unknown ignition source, and at approximately 1736 an explosion occurred at 5992 Colby Hunt Court. Washington Gas stopped the

	flow of gas by squeezing off the main at 1847, creating an outage of 8 customers. Crews have restored gas service to the area. There were no injuries from this incident.

Report number	20240044
Incident date	July 18, 2024
City	Chantilly
County	Fairfax County
State	VA
System part	Main
Installation year	1997
Material	Plastic
Cause	Excavation Damage by Third Party
Root cause or outside force type	Facility Marked Inaccurately Due To Incorrect Facility Records/Maps
Fatalities	0
Injuries	0
Ignition	No
Explosion	No
Narrative	On 7/18/24 at 1506 hrs, Washington Gas received a report of a broken natural gas line near the intersection of Lee Jackson Mem. Hwy & Stringfellow Rd. Chantilly, VA. 20151 from a company working on fiber. On arrival, WG personnel worked with Fairfax County fire and police to secure the scene. Washington Gas gained access on each side of the damaged facility to perform a double squeeze-off operation. This portion of the system was a two-way feed. Washington Gas stopped the gas flow 0109 hrs on 7/19/24 and the roadway was opened just after. On 7/19/24 at 1310 hrs gas was restored to normal operation. Washington Gas does not view this event as 'significant' pursuant to the definition of 'incident' in 49 C.F.R §191.3 (3) (in addition to the event not meeting the criteria for 'incident' pursuant to 49 C.F.R §191.3 (1) and(2)), but is filing this report because the event is an open matter at the Virginia State Corporation Commission.

Report number	20240011
Incident date	January 18, 2024
City	Washington
County	Washington
State	DC

System part	Service Riser
Installation year	1981
Material	Plastic
Cause	Other Outside Force Damage: Damage By Car, Truck, Or Other Motorized Vehicle/Equipment Not Engaged In Excavation
Root cause or outside force type	Damage By Car, Truck, Or Other Motorized Vehicle/Equipment Not Engaged In Excavation
Fatalities	0
Injuries	0
Ignition	Yes
Explosion	Yes
Narrative	On January 18, 2024, at approximately 0930, a delivery truck struck a meter and riser which was located at 1223 Marion Barry Ave SE, Washington D.C.. Washington Gas was notified at 0940 via fireboard of this incident. The resulting damage, which was a broken riser, caused a blowing gas leak. Subsequently, a flash fire occurred on the second floor at 1225 Marion Barry Ave SE. Minutes later, at approximately 1001, an explosion occurred at 1223 Marion Barry Ave SE. One person was injured and was taken to the hospital with minor injuries. The first Washington Gas crew arrived at 1016. Washington Gas stopped the flow of gas using valves at 1251, creating an outage of 36 customers. Crews have restored service to the customers that were affected.

Report number	20230069
Incident date	October 12, 2023
City	Silver Spring
County	Montgomery County
State	MD
System part	Main
Installation year	1978
Material	Steel
Cause	Other Outside Force Damage
Root cause or outside force type	Water Escaping from a Burst Water Main.
Fatalities	0
Injuries	0
Ignition	No
Explosion	No

Narrative	On October 12, 2023, at approximately 17:15 hours Washington Gas was notified of a possible leak at 11301 Mapleview Dr Silver Spring MD. Washington Gas dispatched crews to the location who arrived and performed an assessment of situation, which resulted in the identification of a leaking 4-inch steel main line. Washington Suburban Sanitary Commission was working on a leaking water main in the area that eventually caused the gas main leak. The cause of the leak on the 4-inch gas main line was a leak that originated on a 30-inch water main line at a 100 PSI which created an approximately 3-inch diameter hole at the bottom of the 4-inch gas main. The gas main was submerged in the excavation due to the water leak. On October 14 at approximately 1220 hours the gas was turned off utilizing valves, stopple fitting and squeeze off method.

Report number	20220005
Incident date	December 16, 2021
City	Hyattsville
County	Prince George County
State	MD
System part	Main
Installation year	1955
Material	Steel
Cause	Other Outside Force Damage: Electrical Arcing from Other Equipment or Facility
Root cause or outside force type	Electrical Arcing from Other Equipment or Facility
Fatalities	0
Injuries	0
Ignition	Yes
Explosion	No
Narrative	On December 16, 2021 at approximately 1213 hours Washington Gas was notified of a gas-fed fire in front of 7224 Annapolis Road, Hyattsville, MD. Washington Gas dispatched crews to the location who arrived and performed an assessment of situation, which resulted in the identification of an 8" wrpd main line that was feeding the controlled fire. No Washington Gas crews, or contractors were working at this location at the time of ignition. It was determined that a transformer shorted at Surrey Lane and Annapolis Road, which resulted in an electrical discharge through an adjacent metal fence into the ground. The metal fence that is estimated to be roughly 20 years old was installed directly over the 8" wrpd main. Evidence

	suggests that the electrical discharge from the transformer traveled down the fence and discharged at 7224 Annapolis Road, resulting in an electrical arc to the pipe. The gas was turned off utilizing valves which extinguished the fire. Once the area was deemed safe, crews started permanent repairs to the pipe, including adding new cathodic protection anodes and a test station. The pipe was repaired using a full seal clamp and was not able to be examined for pipe specification and wall thickness as a result. There was only minor property damage, which was to the chain link fence that had to be removed to repair the main.

Report number	20210100
Incident date	November 3, 2021
City	Upper Marlboro
County	Prince George's
State	MD
System part	Main
Installation year	2006
Material	Plastic
Cause	Excavation Damage by Third Party
Root cause or outside force type	Improper Excavation Practice Not Listed Above
Fatalities	0
Injuries	0
Ignition	No
Explosion	No
Narrative	On November 3, 2021, Washington Gas was notified of a damaged facility near Dormansville Blvd. and Church Rd. Upper Marlboro MD. Washington Gas dispatched crews in response to the broken line. Once arrived, the damage was determined to be a two-way feed 8" plastic main. The main was struck on a construction site by a backhoe with a 48" bucket. No traffic was affected due to new culvert and bridge was being constructed. The gas main was approximately 10' under a creek bed known as Black Branch had been previously been diverted due to the construction of a new bridge. The excavator Pleasants Construction did have a valid Miss Utility ticket but failed to maintain marks in the excavation area. Washington Gas excavated on each side of the damaged facility and performed a squeeze off. The work area was made safe to enter to commence repairs.

Report number	20210090

Incident date	September 26, 2021
City	Woodbridge
County	Prince William
State	VA
System part	Outside Meter/Regulator Set
Installation year	1997
Material	Other
Cause	Other Outside Force Damage: Damage by Car, Truck, Or Other Motorized Vehicle/Equipment Not Engaged in Excavation
Root cause or outside force type	Damage By Car, Truck, Or Other Motorized Vehicle/Equipment Not Engaged in Excavation
Fatalities	0
Injuries	0
Ignition	Yes
Explosion	No
Narrative	On 9/26/2021 at approximately 17:15 hrs a vehicle travelling from Hereford Rd to southbound Minneville Rd. left the roadway and travelled approximately 90 feet and struck a meter set assembly supplied by a 3/4" natural gas service, located at 13950 Andorra Dr. Woodbridge, VA. Prince William County fire board notified Washington Gas. Washington Gas responded and located the natural gas service and obtained gas off by squeeze in the area of the front yard of the above address. The driver was transported to the local hospital for precautionary measures. The natural gas service line was capped off due to structural damage to the residence. This report was delayed due to the unknown estimated property damage and site access limitations.

Report number	20210093
Incident date	July 21, 2021
City	Haymarket
County	Prince William
State	VA
System part	Main
Installation year	6/23/1905 0:00
Material	Plastic
Cause	Excavation Damage by Third Party
Root cause or outside force type	Facility Not Marked Due To Locator Error
Fatalities	0

Injuries	0
Ignition	No
Explosion	No
Narrative	On 7/21/21 at 1118 hrs, Washington Gas received a report of a natural gas broken line at John Marshall Highway and Trading Square Haymarket, VA. 20169 from Prince William County fire board. 1119 hrs Washington Gas dispatched field ops crews for response. 1120 hrs Washington Gas received an alarm on SCADA of pressure dropping and pressure operations crews were dispatched. The first field ops crew arrived at 1200 hrs and worked with the fire department to secure the scene and relay information to Washington Gas dispatch for additional support. The first arriving crews began to locate the closest distribution valve. The area of this valve #1 had been recently regraded and had extensive vegetation growth. The crews located a broken portion of a line marker (it had recently been bushed hogged and broken off) and found the valve cover was found under 3-4" of soil. Customer impact through the utilization of critical valves to stop gas, and area of the damage (natural gas venting into the atmosphere in an open lot and the closest structure approximately 300ft. away) were factors considered as part of the response planning. At approximately 1445 hrs Washington Gas pressure ops began to control the flow of natural gas, reducing the pressure to 5psig by use of valve #1. Once the pressure was stabilized crews began to excavate upstream and downstream of the break area to install (2) 2" bypasses. These bypasses were installed to maintain the downstream customers and to use the exposed 12' plastic to double squeeze the pipe. Gas was squeezed off at 0400 hrs on 7/22/2021. Further investigation and repairs commenced. Current valve assignments were revaluated netting an increase of critical vales on the existing infrastructure.

Report number	20210044
Incident date	April 14, 2021
City	North Bethesda
County	Montgomery
State	MD
System part	Main
Installation year	2020
Material	Plastic
Cause	Excavation Damage by Third Party

Root cause or outside force type	Improper Excavation Practice Not Listed Above
Fatalities	0
Injuries	0
Ignition	No
Explosion	No
Narrative	Washington Gas was notified by Montgomery County fire board on 4/14/21 0903 hrs of a damaged facility at the intersection of Old Georgetown Rd. & Executive Blvd. North Bethesda, MD. Washington Gas arrived at 0912 hrs and identified the damaged facilities to be 12" HD plastic main. Anchor Construction was excavating with an backhoe and damaged WG facilities. Washington Gas identified and operated seven critical valves to discontinue the flow of gas. Due to the depth (20') a custom shoring box was designed and built specifically for this site, which took additional time. Washington Gas had to install bypasses around the facilities to introduce gas back to customers. The contractor Anchor Construction was found at fault for not following using soft digging method as required. The intersection mentioned above was already closed due to on-going construction and did not interrupt any additional traffic. As of 04/26/2021 all customers affected have had gas reintroduced and repairs are complete. Washington Gas will provide additional information as it is received in supplemental responses.

Report number	20210026
Incident date	February 3, 2021
City	Springfield
County	Fairfax County
State	VA
System part	Main
Installation year	1988
Material	Plastic
Cause	Pipe, Weld, Or Joint Failure: Fusion Joint
Root cause or outside force type	
Fatalities	0
Injuries	3
Ignition	Yes
Explosion	No

Narrative	On January 6, 2021, an odor was reported to the Washington Gas emergency line on Hooes Road in Springfield, Virginia and a technician was dispatched to the site. The leak was investigated, graded and aspirated. A BGO crew was dispatched the following day. The crew excavated the hole and found a small leak on a butt fusion bead on a 1988 Aldyl-A 6" plastic main, operating at 55 psig. Consistent with company procedure, the crew installed a temporary Straub open-flex clamp, verified that the site was safe, and referred the repair for a cut-out. On February 3, 2021, two Washington Gas crews were dispatched to 8530 Hooes Rd to complete the permanent repair by replacing the pipe segment containing the clamp. At approximately 12:22, during the process of sliding the clamp, leaking gas ignited. All employees that were transported have since been released from the hospital. Final repairs have been made. Washington Gas performed laboratory testing on the failed segment of pipe. The testing found the initial leak had been caused by a failed 1988 butt fusion joint that exhibited inadequate fusion. By the visual evaluation criteria in place at the time this gas main was installed, the butt fusion would have been deemed acceptable. However, the subject butt fusion was likely not initially made with sufficient force applied to the heated pipe ends to create a full strength fusion. Additional: Part E 3.b Date MAOP established: 12/28/1988 installed was completed before 12/28/1988, exact date of pressure test unknown

Report number	20200035
Incident date	February 14, 2020
City	Potomac Falls
County	Loudoun County
State	VA
System part	Main
Installation year	1995
Material	Plastic
Cause	Excavation Damage by Third Party
Root cause or outside force type	Old Ticket No Longer Valid
Fatalities	0
Injuries	0
Ignition	No
Explosion	No

Narrative	NRC 48hr update #1271349 Atlantic Construction Company 516 Jack Enders Blvd. Unit A Berryville, VA 22611 directional drilling hit a 8" plastic natural gas main on February 14, 2020. Washington Gas contract locator failed to mark ticket b002801077 in its entirety (56-265. 19a) The excavator had initiated a remark on 2/12/20 a004300525 due to weather. That notification had not been marked and cleared through the call center, and therefore the excavator did not possess a valid ticket (56-265.17 d). Pipeline repairs are complete.

Report number	20200013
Incident date	December 26, 2019
City	Not Within a Municipality
County	Not Within a County or Parish
State	DC
System part	Main
Installation year	2019
Material	Plastic
Cause	Excavation Damage by Third Party
Root cause or outside force type	No Notification Made to the One-Call Center/811
Fatalities	0
Injuries	0
Ignition	No
Explosion	No
Narrative	Paving contractor Anderson Company, working for the District of Columbia used an excavator and hit a 2" plastic service tee. NRC notification was made due to shut down of Navy Yard Ballpark Metro station by DC fire department. The station was monitored by DC FD & WG. No indications of natural gas were found. 48hr follow up NRC # 1267452

Report number	20200010
Incident date	December 15, 2019
City	Fairfax Station
County	Fairfax County
State	VA
System part	District Regulator/Metering Station
Installation year	2002
Material	Steel

Cause	Other Outside Force Damage: Damage by Car, Truck, Or Other Motorized Vehicle/Equipment Not Engaged in Excavation
Root cause or outside force type	Damage By Car, Truck, Or Other Motorized Vehicle/Equipment Not Engaged in Excavation
Fatalities	0
Injuries	0
Ignition	No
Explosion	No
Narrative	48hr follow-up NRC # 1266661 on, 12/15/19 at approximately 0045 hrs., Washington Gas was notified by Fairfax County fireboard of damaged facility near the intersection of Ox Rd. & Clara Barton Dr. Fairfax, VA. Washington Gas identified the facility to be station #390, damaged by a vehicle that had travelled through the safety bollards and security enclosure box. Washington Gas secured the station by closing the station valves, isolating the damaged facilities. There were no customers affected, as area was a two-way feed. The area of gas release was on 6"x4" reducer and 4" strainer. Other parts of the facility piping were bent due to impact.

Report number	20190032
Incident date	February 26, 2019
City	Largo
County	Prince George's County
State	MD
System part	Main
Installation year	2018
Material	Plastic
Cause	Excavation Damage by Third Party
Root cause or outside force type	Marks Faded or Not Maintained
Fatalities	0
Injuries	0
Ignition	No
Explosion	No
Narrative	Washington Gas received a call from a third-party excavator at 1:56pm on Tuesday, February 26, 2019. Upon arrival, Washington Gas found a 12-inch plastic main pipe had been damaged during excavation and gas was blowing. Washington Gas crews reduced natural gas pressure in the area to minimize gas lost. Washington Gas shut the main down by squeeze-off at 9:07pm on February 26, 2019,

	which resulted in an outage of 767 residential customers and 44 commercial customers. The damaged section was cut out and replaced and the main was re-energized on February 27, 2019. On Wednesday, February 27, Washington Gas found that Miss Utility marks had not been preserved on the site.

Report number	20180089
Incident date	August 28, 2018
City	Winchester
County	Frederick County
State	VA
System part	Main
Installation year	1967
Material	Steel
Cause	Other Outside Force Damage
Root cause or outside force type	3rd Party Damage by Chop Saw.
Fatalities	0
Injuries	1
Ignition	Yes
Explosion	No
Narrative	Fuog Interbuild working for Frederick County installing sewer used a chop saw to cut through 2" steel gas main causing ignition. Fuog Interbuild was working outside the area of its one call ticket, dug when no marks or flags were present, and did not call for a re-mark when the gas main was exposed. Virginia State Corporation Commission has concluded their investigation of the incident at 100 Potomac Place Winchester, VA. VA SCC has determined that no probable violations of the Virginia Damage Prevention Act and Commission rules for enforcement of the Damage Prevention Act were committed by Washington Gas. The Division's damage prevention staff also performed their investigation and had determined that no potential non-compliances with the Commission's pipeline safety standards exist as to Washington Gas. With Staff's findings of no non-compliance issues, Washington Gas respectfully closes this report.

Report number	20160086
Incident date	August 11, 2016
City	Silver Spring
County	Montgomery County

State	MD
System part	Other
Installation year	UNKNOWN
Material	Other
Cause	Other Incident Cause: Unknown
Root cause or outside force type	
Fatalities	7
Injuries	33
Ignition	Yes
Explosion	No
Narrative	On August 10, 2016 an explosion and fire occurred at 8701 Arliss Street in Silver Spring, Maryland. The National Transportation Safety Board (NTSB) concluded that the probable cause of the explosion in building 8701 was the failure of an indoor mercury service regulator. Washington Gas believes the evidence, including multiple sources of natural gas onsite that could have contributed to the incident, does not permit a conclusive determination of probable cause. Thus, for the purposes of this report, Washington Gas avers that the actual cause remains undetermined. Nonetheless, Washington Gas has implemented all safety recommendations promulgated by the NTSB with respect to the incident, including expedited removal of mercury service regulators remaining on the Company's system. The Maryland Public Service Commission approved Washington Gas' expedited removal program on December 18, 2020.

Report number	20160023
Incident date	February 7, 2016
City	Woodbridge
County	Prince William County
State	VA
System part	Service
Installation year	1963
Material	Copper
Cause	Corrosion Failure: External Corrosion
Root cause, outside force type, or corrosion type	Corrosive Soil
Fatalities	0
Injuries	0

Ignition	Yes
Explosion	Yes
Narrative	On Sunday, February 7, 2016, at approximately 15:18, Washington Gas received a call from the Prince William County fire department relative to an outside gas odor located at 14100 Franklin St. in Woodbridge, VA. Washington Gas personnel arrived on scene at 15:31. Upon arrival, the Washington Gas technician had exited his vehicle and was applying the appropriate PPE when a possible low order explosion occurred. There were no injuries or fatalities as a result of the incident. An odorant sample was taken and the level of odorant was determined to be acceptable.

Attachment **ASH-9**
Title **STRIDE service line projects selected based on leak frequency, with benefit-cost results**

Assumption	Cost per leak	$5,500	*ASH Direct Testimony, Section VII-B*
Assumption	Annual carrying cost	9.14%	*ASH Direct Testimony, Section VII-B*
Assumption	Average service life	60	*ASH Direct Testimony, Section VII-C*

Source	*KMM-02b*	*KMM-02b*	*KMM-02b*	*KMM-02b*	*KMM-02b*	*KMM-02b*
Col	*a*	*b*	*c*	*d*	*e*	*f*
	Project ID	***GPIS Additions***	***Projected Leaks per 100 Services***	***Program***	***Services***	***STRIDE Filing Estimated Cost ($) (Includes Cost of Removal)***
	BCA0304213	$ 404,364	52.94	3	23	$ 404,800
	BCA0304237	$ 409,562	34.24	3	38	$ 543,348
	BCA0304233	$ 413,799	34.38	3	30	$ 423,900
	BCA0305248	$ 419,563	33.33	3	19	$ 347,500
	BCA0304216	$ 427,044	50	3	16	$ 442,200
	BCA0304205	$ 429,473	69.64	3	24	$ 605,800
	BCA0304226	$ 431,903	38.24	3	22	$ 364,800
	BCA0304198	$ 434,295	80	1C	11	$ 446,100
	BCA0304231	$ 438,969	34.78	3	26	$ 458,100
	BCA0306230	$ 439,906	87.5	3	20	$ 406,160
	BCA0305257	$ 446,611	33.33	3	31	$ 473,700
	BCA0301282	$ 448,280	50	1A	41	$ 523,358
	BCA0305255	$ 450,783	33.33	1C	17	$ 273,600
	BCA0304222	$ 457,464	42.11	3	27	$ 525,500
	BCA0304225	$ 464,670	38.3	3	27	$ 522,500
	BCA0304190	$ 480,291	87.5	3	31	$ 521,000
	BCA0305267	$ 488,895	31.71	3	26	$ 543,100
	BCA0304217	$ 493,085	45.83	3	25	$ 469,700
	BCA0306301	$ 497,975	87.5	3	36	$ 715,784
	BCA0304193	$ 528,304	85.71	1B	31	$ 416,000
	BCA0305262	$ 550,651	32.97	3	31	$ 504,400
	BCA0304243	$ 570,874	33.52	3	34	$ 633,000
	BCA0304235	$ 580,012	34.38	3	33	$ 554,500
	BCA0301278	$ 592,482	66.67	1A	38	$ 667,664
	BCA0304203	$ 595,058	71.43	3	32	$ 388,600
	BCA0305250	$ 651,698	33.33	3	37	$ 786,200
	BCA0305266	$ 661,161	32.04	3	36	$ 712,800
	BCA0304240	$ 661,509	34.24	3	54	$ 758,610
	BCA0306204	$ 675,643	75.86	3	27	$ 532,836
	BCA0305265	$ 689,599	32.04	3	33	$ 691,600
	BCA0305249	$ 712,198	33.33	3	21	$ 369,088
	BCA0304212	$ 751,457	55.56	3	24	$ 685,900
	BCA0304242	$ 777,734	33.52	3	42	$ 829,000
	BCA0304174	$ 839,132	94.39	3	30	$ 818,700
	BCA0305254	$ 846,777	33.33	3	38	$ 710,600
	BCA0306197	$ 915,035	68.75	3	39	$ 754,000
	BCA0305264	$ 920,369	32.43	3	46	$ 879,300
	BCA0305245	$ 924,071	33.33	3	31	$ 981,100
	BCA0304223	$ 969,830	42.11	3	38	$ 736,700
	BCA0304241	$ 970,982	33.52	3	42	$ 747,100
	BCA0304183	$ 1,215,110	88.89	1A	44	$ 1,016,700
	BCA0305263	$ 1,222,417	32.97	3	28	$ 515,900
	BCA0305244	$ 1,445,914	33.33	3	43	$ 1,335,700
Total		$27,744,948	48.30		1342	$26,036,948
Program 3 Total		$24,075,694				

Calculated g=f/e	*Calculated h=c/60/100*$5,500*	*Calculated i=g*9.14%*	*Calculated j=h/i*
Estimated cost per service	***Annual reduction in expected leak repair costs, per service***	***Expected annual carrying cost of replacement, per service***	***Benefit:cost ratio***
$ 17,600	$48.5	$ 1,609	**0.030**
$ 14,299	$31.4	$ 1,307	**0.024**
$ 14,130	$31.5	$ 1,291	**0.024**
$ 18,289	$30.6	$ 1,672	**0.018**
$ 27,638	$45.8	$ 2,526	**0.018**
$ 25,242	$63.8	$ 2,307	**0.028**
$ 16,582	$35.1	$ 1,516	**0.023**
$ 40,555	$73.3	$ 3,707	**0.020**
$ 17,619	$31.9	$ 1,610	**0.020**
$ 20,308	$80.2	$ 1,856	**0.043**
$ 15,281	$30.6	$ 1,397	**0.022**
$ 12,765	$45.8	$ 1,167	**0.039**
$ 16,094	$30.6	$ 1,471	**0.021**
$ 19,463	$38.6	$ 1,779	**0.022**
$ 19,352	$35.1	$ 1,769	**0.020**
$ 16,806	$80.2	$ 1,536	**0.052**
$ 20,888	$29.1	$ 1,909	**0.015**
$ 18,788	$42.0	$ 1,717	**0.024**
$ 19,883	$80.2	$ 1,817	**0.044**
$ 13,419	$78.6	$ 1,227	**0.064**
$ 16,271	$30.2	$ 1,487	**0.020**
$ 18,618	$30.7	$ 1,702	**0.018**
$ 16,803	$31.5	$ 1,536	**0.021**
$ 17,570	$61.1	$ 1,606	**0.038**
$ 12,144	$65.5	$ 1,110	**0.059**
$ 21,249	$30.6	$ 1,942	**0.016**
$ 19,800	$29.4	$ 1,810	**0.016**
$ 14,048	$31.4	$ 1,284	**0.024**
$ 19,735	$69.5	$ 1,804	**0.039**
$ 20,958	$29.4	$ 1,916	**0.015**
$ 17,576	$30.6	$ 1,606	**0.019**
$ 28,579	$50.9	$ 2,612	**0.019**
$ 19,738	$30.7	$ 1,804	**0.017**
$ 27,290	$86.5	$ 2,494	**0.035**
$ 18,700	$30.6	$ 1,709	**0.018**
$ 19,333	$63.0	$ 1,767	**0.036**
$ 19,115	$29.7	$ 1,747	**0.017**
$ 31,648	$30.6	$ 2,893	**0.011**
$ 19,387	$38.6	$ 1,772	**0.022**
$ 17,788	$30.7	$ 1,626	**0.019**
$ 23,107	$81.5	$ 2,112	**0.039**
$ 18,425	$30.2	$ 1,684	**0.018**
$ 31,063	$30.6	$ 2,839	**0.011**
$19,401.60	$44.3	$ 1,773	**0.025**