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July 28, 2017

NWN OPUC Advice No. 17-12 / UG 334
(UM 1496)

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
Attention: Filing Center
201 High Street SE, Suite 100
Post Office Box 1088
Salem, Oregon 97308-1088

**Re: Annual Purchased Gas Cost and Technical Rate Adjustments
UM 1496: Request for Amortization of Certain Deferred Accounts
Relating to Gas Costs**

Northwest Natural Gas Company, dba NW Natural (“NW Natural” or the “Company”), files herewith revisions to its Tariff, P.U.C. Or. 25¹ (“the Tariff”), stated to become effective with service on and after November 1, 2017, as follows:

Fifth Revision of Sheet P-2,
Schedule P,
“Purchased Gas Cost Adjustments (continued)”

Fifth Revision of Sheet P-3,
Schedule P,
“Purchased Gas Cost Adjustments (continued);”

Sixth Revision of Sheet P-5,
Schedule P,
“Purchased Gas Cost Adjustments (continued);”

Seventh Revision of Sheet 162-1,
Schedule 162,
“Temporary (Technical) Adjustments to Rates;”

Seventh Revision of Sheet 162-2,
Schedule 162,
“Temporary (Technical) Adjustments to Rates (continued);” and

Sixth Revision of Sheet 164-1,
Schedule 164,
“Purchased Gas Cost Adjustments to Rates.”

This filing is made in accordance with OAR 860-022-0025, OAR 860-022-0030, and OAR 860-022-0070.

¹ Tariff P.U.C. Or. 25 originated November 1, 2012 with Docket UG 221; OPUC Order No. 12-408 as supplemented by Order No. 12-437, and was filed pursuant to ORS 767.205 and OAR 860-022-0005.

Introduction and Summary

The purpose of this filing is to:

(1) Develop the temporary rate adjustments associated with the amortization of gas cost credit or debit balances in Federal Energy Regulatory Commission (FERC) Account 191, deferred under Docket UM 1496 and proposed to be effective November 1, 2017, and to show the removal of temporary rate adjustments incorporated into rates effective November 1, 2016; and

(2) Develop the commodity (Weighted Average Cost of Gas "WACOG") and non-commodity ("demand" or "pipeline capacity" charge) purchased gas costs to be effective November 1, 2017.

The Company revises rates for these purposes annually; its last filing was effective November 1, 2016.

The number of customers affected by the changes proposed in this filing is 588,720 residential customers, 60,765 commercial customers, and 673 industrial customers.

In addition to the supporting materials submitted as part of this filing, the Company will separately submit work papers in electronic format, all of which are incorporated herein by reference.

I. Amortization of Gas Cost Deferrals (UM 1496) and removal of Temporary Rate Adjustments Currently in Effect

The net effect of this portion of the filing is to decrease the Company's annual revenues by \$15,215,592, or about -2.36%; the effect of removing the Account 191 temporary adjustments placed into rates November 1, 2016, is an increase of \$408,763; and the effect of applying the new Account 191 temporary rate adjustments for the amortization of gas costs deferred under Docket UM 1496 is a decrease of \$15,624,355.

The proposed adjustments to customer rates are comprised of the following: (1) a credit of \$0.00836 per therm for all sales service customers related to the 191 commodity accounts, and (2) a credit of \$0.01656 per therm for all firm sales service customers and a credit of \$0.00197 per therm for all interruptible sales service customers related to 191 demand accounts. The net effect of all Account 191 amortizations is a credit of \$0.02492 per therm for firm sales service customers and a credit of \$0.01033 per therm for interruptible sales service customers.

The Company has developed the adjustments to rates proposed in this filing in accordance with the PGA Filing Guidelines as prescribed by the most recent Commission Order in Docket UM 1286.

This portion of the filing is in compliance with ORS 757.259 (2003), which authorizes deferred utility expenses or revenues to be allowed (amortized) in rates to the extent authorized by the Commission in a proceeding to change rates. All of the deferrals included in this filing occurred with appropriate application by Commission authorization, as rate orders or under approved tariffs.

II. Purchased Gas Cost Adjustment (PGA)

The net effect of the PGA portion of this filing is to decrease the Company's annual revenues by about \$12,714,776, or about -1.97%; the change in commodity cost is a decrease of \$11,344,389 and the change in demand cost is a decrease of \$1,370,387.

The change in gas costs results in a proposed Annual Sales WACOG of \$0.28932 per therm, and a proposed Winter Sales WACOG of \$0.32400. Revenue sensitive effects are applied for billing purposes, resulting in a proposed Annual Sales Billing WACOG of \$0.29764 and a proposed Winter Sales Billing WACOG of \$0.33332.

The change in demand costs results in a proposed firm service pipeline capacity charge of \$0.11588 per therm, or \$1.72 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of \$0.01379 per therm. Revenue sensitive effects are applied for billing purposes, resulting in a proposed firm service pipeline capacity charge of \$0.11921 per therm or \$1.77 per therm of MDDV, and a proposed interruptible service pipeline capacity charge of \$0.01419 per therm.

If there are material changes in the Company's gas supply costs or costs associated with pipeline services and charges from the levels used to develop the purchased gas adjustments included in this filing, then the Company will reflect such changes to Oregon gas customers in a manner approved by the Commission.

This filing applies the method for calculating the proposed Annual Sales Weighted Average Cost of Gas ("WACOG") that is set forth in a joint party stipulation approved by the Commission in OPUC Order No. 08-504, Docket UM 1286, as modified by the approval of a stipulation affirmed in OPUC Order No. 11-176, Dockets UM 1520/UG 204, and as further prescribed by the PGA Filing Guidelines, Section VI (1)(d) adopted in the most recent Commission Order No. 14-238 in Docket UM 1286.

III. Combined Effect on Customer Bills

The combined effects of this filing is to decrease the Company's annual revenues by about \$27,930,368, or about -4.33%; the change in purchased gas costs is a decrease of \$12,714,776 and the change in temporary adjustments to rates is a decrease of \$15,215,592.

The average monthly bill impact of the changes proposed in this filing is shown in the table below:

| Class | Rate Schedule | Average Monthly Bill Change (\$) | Average Monthly Bill Change (%) |
|--------------------------------|----------------------|---|--|
| Residential | Schedule 2 | -\$2.25 | -4.2% |
| Commercial | Schedule 3 | -\$10.39 | -4.8% |
| Commercial Firm Sales | Schedule 31 | -\$123.43 | -6.1% |
| Industrial Firm Sales | Schedule 32 | -\$813.50 | -9.0% |
| Industrial Interruptible Sales | Schedule 32 | -\$560.86 | -3.6% |

The monthly bill effects for all other rate classes can be found in the separately provided work papers.

Please note that the monthly bill effects for Rate Schedule 31 and Rate Schedule 32 do not include the effect of changes in the pipeline capacity charge due to the customer option to elect either an MDDV-based capacity charge or a volumetric-based capacity charge. If a customer served under Rate Schedule 32 Industrial Firm Sales Service elected the volumetric pipeline capacity option, the change in the monthly bill effective November 1, 2017 would be a decrease of \$853.51, or -7.5%.

UM 1286 Natural Gas Portfolio Development Guidelines

In addition to the supporting materials submitted as part of this filing as Exhibit A and Exhibit B, the Company provides Exhibit C which contains the data required by the Natural Gas Portfolio Development Guidelines Sections IV and V as adopted by the Commission in OPUC Order No. 11-196 in Docket UM 1286 ("the OPUC Order"). Some of the information is confidential and highly confidential and is subject to the Modified Protective Order in Docket UM 1286, Order No. 10-337.

Commission Staff's Attachment A through Attachment D, required by Section 5 of the PGA Filing Guidelines, are included in the Company's work papers, incorporated herein by reference, which will be submitted under separate cover.

The Company requests that the tariff sheets filed herewith be permitted to become effective with service on and after November 1, 2017.

In accordance with ORS 757.205, copies of this letter and the filing made herewith are available in the Company's main office in Oregon and on its website at www.nwnatural.com.

Notice to customers will be made in accordance with OAR 860-022-0017.

Please address correspondence on this matter to Kyle Walker at kyle.walker@nwnatural.com with copies to:

eFiling
Rates & Regulatory Affairs
NW Natural
220 NW Second Avenue
Portland, Oregon 97209
Telecopier: (503) 721-2516
Telephone: (503) 226-4211, x3589
eFiling@nwnatural.com

Sincerely,

NW NATURAL

/s/ Gail Hammer

Gail Hammer
Rates & Regulatory Affairs

Attachments: Exhibit A – Purchased Gas Cost Deferral Amortizations
Exhibit B – Purchased Gas Costs
Exhibit C – PGA Portfolio Guidelines Sections IV and V

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Fifth Revision of Sheet P-2
Cancels Fourth Revision of Sheet P-2

SCHEDULE P PURCHASED GAS COST ADJUSTMENTS (continued)

DEFINITIONS (continued):

7. Estimated Annual Sales Weighted Average Cost of Gas (Annual Sales WACOG):
The estimated Annual Sales WACOG is the default Commodity Component for billing purposes, and is used for purposes of calculating the monthly gas cost deferral costs for entry into the Account 191 sub-accounts calculated by the following formula: (Forecasted Purchases at Adjusted Contract Prices) divided by forecasted sales volumes.
- a. "Forecasted Purchases" means November 1 – October 31 forecasted sales volumes, "weather-normalized", plus a percentage for distribution system LUFG.
 - b. "Distribution system embedded LUFG" means the 5-year average of actual distribution system LUFG, not to exceed 2%.
 - c. "Adjusted contract prices" means actual and projected contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel use and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

| | | |
|---|------------------|-----|
| Effective: November 1, 2017: | | (T) |
| Estimated Annual Sales WACOG per therm (w/ revenue sensitive): | \$0.29764 | (R) |
| Estimated Annual Sales WACOG per therm (w/o revenue sensitive): | \$0.28932 | (R) |

8. Estimated Winter Sales WACOG: The Company's weighted average Commodity Cost of Gas for the five-month period November through March.

| | | |
|---|------------------|-----|
| Effective: November 1, 2017: | | (T) |
| Estimated Winter Sales WACOG per therm (w/ revenue sensitive): | \$0.33332 | (I) |
| Estimated Winter Sales WACOG per therm (w/o revenue sensitive): | \$0.32400 | (I) |

9. Estimated Non-Commodity Cost: Estimated annual Non-Commodity gas costs shall be equal to estimated annual Demand Costs, less estimated annual Capacity Release Benefits, plus or minus estimated annual pipeline refunds or surcharges.

10. Estimated Non-Commodity Cost per Therm – Firm Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Firm Sales Service divided by November 1 – October 31 forecasted Firm Sales Service volumes.

| | | |
|--|------------------|-----|
| Effective: November 1, 2017: | | (T) |
| Estimated Non-Commodity Cost per therm-Firm Sales (w/revenue sensitive): | \$0.11921 | (R) |
| Estimated Non-Commodity Cost per therm-Firm Sales (w/o revenue sensitive): | \$0.11588 | (R) |

(continue to Sheet P-3)

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SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

DEFINITIONS (continued):

11. Estimated Non-Commodity Cost per Therm – Interruptible Sales: The portion of the Estimated annual Non-Commodity Cost applicable to Interruptible Sales Service divided by November 1 – October 31 forecasted Interruptible Sales Service volumes.

| | | |
|---|------------------|-----|
| Effective: November 1, 2017: | | (T) |
| Estimated Non-Commodity Cost per therm-Interruptible Sales (w/revenue sensitive): | \$0.01419 | (R) |
| Estimated Non-Commodity Cost per therm-Interruptible Sales (w/o revenue sensitive): | \$0.01379 | (R) |

12. Estimated Non-Commodity Cost per Therm – MDDV Based Sales: The portion of the Estimated annual Non-Commodity Cost applicable to MDDV Based Sales Service.

| | | |
|--|---------------|-----|
| Effective: November 1, 2017: | | (T) |
| Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/revenue sensitive): | \$1.77 | (R) |
| Estimated Non-Commodity Cost per therm-MDDV Based Sales (w/o revenue sensitive): | \$1.72 | (R) |

13. Actual Monthly Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service therms, excluding MDDV based volumes, adjusted for estimated unbilled Firm Sales Service therms.

14. Actual Monthly Interruptible Sales Service Volumes: The total actual monthly billed Interruptible Sales Service therms, adjusted for estimated unbilled Interruptible Sales Service therms.

15. Actual Monthly MDDV Based Firm Sales Service Volumes: The total actual monthly billed Firm Sales Service Volumes for Rate Schedule 31 and Rate Schedule 32 customers billed under the Firm Pipeline Capacity Charge - Peak Demand option, adjusted for estimated unbilled MDDV Firm Sales Service Volumes.

16. Embedded Commodity Cost: The Estimated Annual Sales WACOG, updated for October 31 storage inventory prices, multiplied by the Total of the Actual Monthly Firm and Interruptible Sales Service Volumes.

17. Embedded Non-Commodity Cost per Therm – Firm Sales Service: The Estimated Non-Commodity Cost per Therm - Firm Sales Service multiplied by the Actual Monthly Firm Sales Service Volumes.

18. Embedded Non-Commodity Cost per Therm – Interruptible Sales Service: The Estimated Non-Commodity Cost per Therm – Interruptible Sales Service multiplied by the Actual Monthly Interruptible Sales Service Volumes.

(continue to Sheet P-4)

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and after November 1, 2017

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Sixth Revision of Sheet P-5
Cancels Fifth Revision of Sheet P-5

SCHEDULE P
PURCHASED GAS COST ADJUSTMENTS
(continued)

CALCULATION OF MONTHLY GAS COSTS FOR DEFERRAL PURPOSES (continued):

1. A debit or credit entry shall be made equal to 100% of the difference between the monthly Actual Non-Commodity Cost and the Monthly Embedded Non-Commodity Cost, net of revenue sensitive effects
2. A debit or credit entry shall be made equal to 100% of any monthly difference between actual monthly fixed charge recoveries and Monthly Seasonalized Fixed Charges. The Monthly Seasonalized Fixed Charges for the period November 1, 2017 through October 31, 2018 are:

| | | |
|---------------------|------|---------------------|
| November | 2017 | \$7,991,273 |
| December | 2017 | \$11,683,396 |
| January | 2018 | \$11,182,715 |
| February | 2018 | \$8,969,606 |
| March | 2018 | \$7,619,109 |
| April | 2018 | \$5,464,333 |
| May | 2018 | \$3,775,627 |
| June | 2018 | \$2,624,229 |
| July | 2018 | \$2,249,924 |
| August | 2018 | \$2,223,727 |
| September | 2018 | \$2,494,689 |
| October | 2018 | \$4,657,040 |
| ANNUAL TOTAL | | \$70,935,668 |

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3. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Cost and the Embedded Commodity Cost. A debit or credit entry will also be made equal to 100% of the difference between storage withdrawals priced at the actual book inventory rate as of October 31 prior to the PGA year and storage withdrawals priced at the inventory rate used in the PGA filing. For any given tracker year, if the total activity subject to debit or credit entries that is related to the Gas Reserves transaction exceeds \$10 million, amounts beyond \$10 million will be recorded at 100%.
4. Monthly differentials shall be deemed to be positive if actual costs exceed embedded costs and to be negative if actual costs fall below embedded costs.
5. The cost differential entries shall be debited to the sub-accounts of Account 191 if positive, and credited to the sub-accounts of Account 191 if negative.
6. Interest – Beginning November 1, 2007, the Company shall compute interest on existing deferred balances on a monthly basis using the interest rate(s) approved by the Commission.
(continue to Sheet P-6)

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Effective with service on
and after November 1, 2017

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Seventh Revision of Sheet 162-1
Cancels Sixth Revision of Sheet 162-1

SCHEDULE 162 TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES

PURPOSE:

To identify adjustments to rates in the Rate Schedules listed below that relate to the amortization of balances in the Company's Account 191 deferred revenue and gas cost accounts.

APPLICABLE:

To the following Rate Schedules of this Tariff:

Rate Schedule 2 Rate Schedule 27 Rate Schedule 32
Rate Schedule 3 Rate Schedule 31 Rate Schedule 33

APPLICATION TO RATE SCHEDULES:

Effective: November 1, 2017

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The Total Adjustment amount shown below is included in the Temporary Adjustments reflected in the above-listed Rate Schedules. NO ADDITIONAL ADJUSTMENT TO RATES IS REQUIRED.

| Schedule | Block | Account 191 Commodity Adjustment | Account 191 Pipeline Capacity Adjustment | Total Adjustment |
|----------|---------|--|---|--------------------|
| 2 | | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| 3 CSF | | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| 3 ISF | | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| 27 | | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| 31 CSF | Block 1 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 2 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| 31 CTF | Block 1 | N/A | N/A | \$0.00000 |
| | Block 2 | N/A | N/A | \$0.00000 |
| 31 ISF | Block 1 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 2 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| 31 ITF | Block 1 | N/A | N/A | \$0.00000 |
| | Block 2 | N/A | N/A | \$0.00000 |

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(continue to Sheet 162-2)

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NWN OPUC Advice No. 17-12

Effective with service on
and after November 1, 2017

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Seventh Revision of Sheet 162-2
Cancels Sixth Revision of Sheet 162-2

SCHEDULE 162 TEMPORARY (TECHNICAL) ADJUSTMENTS TO RATES (continued)

APPLICATION TO RATE SCHEDULES (continued):

Effective: November 1, 2017

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GENERAL TERMS:

This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Schedule apply to service under this Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

| Schedule | Block | Account 191 Commodity Adjustment [1] | Account 191 Pipeline Capacity Adjustment | Total Adjustment |
|------------|---------|--|--|--------------------|
| 32 CSF | Block 1 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 2 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 3 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 4 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 5 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 6 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| 32 ISF | Block 1 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 2 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 3 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 4 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 5 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| | Block 6 | (\$0.00836) | (\$0.01656) | (\$0.02492) |
| 32 CTF/ITF | Block 1 | N/A | N/A | \$0.00000 |
| | Block 2 | N/A | N/A | \$0.00000 |
| | Block 3 | N/A | N/A | \$0.00000 |
| | Block 4 | N/A | N/A | \$0.00000 |
| | Block 5 | N/A | N/A | \$0.00000 |
| | Block 6 | N/A | N/A | \$0.00000 |
| 32 CSI | Block 1 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 2 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 3 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 4 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 5 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 6 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| 32 ISI | Block 1 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 2 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 3 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 4 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 5 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| | Block 6 | (\$0.00836) | (\$0.00197) | (\$0.01033) |
| 32 CTI/ITI | Block 1 | N/A | N/A | \$0.00000 |
| | Block 2 | N/A | N/A | \$0.00000 |
| | Block 3 | N/A | N/A | \$0.00000 |
| | Block 4 | N/A | N/A | \$0.00000 |
| | Block 5 | N/A | N/A | \$0.00000 |
| | Block 6 | N/A | N/A | \$0.00000 |
| 33 TI | | N/A | N/A | \$0.00000 |
| 33 TF | | N/A | N/A | \$0.00000 |

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Issued July 28, 2017
NWN OPUC Advice No. 17-12

Effective with service on
and after November 1, 2017

NORTHWEST NATURAL GAS COMPANY

P.U.C. Or. 25

Sixth Revision of Sheet 164-1
Cancels Fifth Revision of Sheet 164-1

SCHEDULE 164 PURCHASED GAS COST ADJUSTMENT TO RATES

PURPOSE:

To identify the Commodity and Pipeline Capacity Components applicable to the Rate Schedules listed below.

APPLICABLE:

To the following Rate Schedules of this Tariff:

Rate Schedule 2 Rate Schedule 3 Rate Schedule 27
Rate Schedule 31 Rate Schedule 32

APPLICATION TO RATE SCHEDULES:

Effective: November 1, 2017

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| | |
|---|-----------|
| Annual Sales WACOG [1] | \$0.29764 |
| Winter Sales WACOG [2] | \$0.33332 |
| Firm Sales Service Pipeline Capacity Component [4] | \$0.11921 |
| Firm Sales Service Pipeline Capacity Component [5] | \$1.77 |
| Interruptible Sales Service Pipeline Capacity Component [6] | \$0.01419 |

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- [1] Applies to all Sales Service Rate Schedules (per therm) except where Winter Sales WACOG or Monthly Incremental Cost of Gas applies.
- [2] Applies to Sales Customers that request Winter Sales WACOG at the September 15 Annual Service Election.
- [3] Applies to Rate Schedules 2, 3, and Schedule 31 and Schedule 32 Firm Sales Service Volumetric Pipeline Capacity option (per therm).
- [4] Applies to Rate Schedules 31 and 32 Firm Sales Service Peak Demand Pipeline Capacity option (per therm of MDDV per month).
- [5] Applies to Rate Schedule 32 Interruptible Sales Service (per therm).

GENERAL TERMS:

This schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff, any other schedules that by their terms or by the terms of this Rate Schedule apply to service under the Rate Schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

Issued July 28, 2017
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Effective with service on
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EXHIBIT A

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost Deferral Amortizations
UM 1496

NWN OPUC Advice No. 17-12 / UG 334

July 28, 2017

NW NATURAL

EXHIBIT A

Supporting Materials

Purchased Gas Cost Deferral Amortizations – UM 1496

NWN OPUC ADVICE NO. 17-12 / UG 334

| Description | Page |
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| Summary of Temporary Increments | 1 |
| Calculation of Increments Allocated on the Equal Cent per Therm Basis | 2 |
| Basis for Revenue Related Costs | 3 |
| PGA Effects on Revenue | 4 |
| Summary of Deferred Accounts Included in the PGA | 5 |
| 191400 Core Market Commodity Gas Cost Deferral | 6 |
| 191401 Amortization of Oregon WACOG Deferral | 7 |
| 191410 Core Market Demand Cost Deferral | 8 |
| 191411 Amortization of Oregon Demand Deferral | 9 |
| 191417 Coos County Demand | 10 |
| 191450 Core Market Demand Collection Deferral | 11 |

NW Natural
Rates & Regulatory Affairs
2017-18 PGA - Oregon: August Filing
Summary of TEMPORARY Increments

| | | | Current | WACOG | Demand | Demand | |
|----|------------------|---------|-------------|-------------|-------------|---------------|-------------|
| | | | Temporaries | Deferral | Deferral - | Deferral - | Subtotal |
| | | | | | FIRM | INTERRUPTIBLE | |
| | Schedule | Block | A | B | C | D | E |
| 4 | 2R | | \$0.02604 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 5 | 3C Sales Firm | | \$0.07356 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 6 | 3I Sales Firm | | \$0.04138 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 7 | 27 Dry Out | | \$0.01693 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 8 | 31C Sales Firm | Block 1 | \$0.07048 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 9 | | Block 2 | \$0.06959 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 10 | 31C Trans Firm | Block 1 | \$0.01139 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 11 | | Block 2 | \$0.01042 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 12 | 31I Sales Firm | Block 1 | \$0.03737 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 13 | | Block 2 | \$0.03665 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 14 | 31I Trans Firm | Block 1 | \$0.00892 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 15 | | Block 2 | \$0.00809 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 16 | 32C Sales Firm | Block 1 | \$0.03666 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 17 | | Block 2 | \$0.03561 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 18 | | Block 3 | \$0.03388 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 19 | | Block 4 | \$0.03214 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 20 | | Block 5 | \$0.03090 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 21 | | Block 6 | \$0.03021 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 22 | 32I Sales Firm | Block 1 | \$0.03491 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 23 | | Block 2 | \$0.03415 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 24 | | Block 3 | \$0.03289 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 25 | | Block 4 | \$0.03163 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 26 | | Block 5 | \$0.03068 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 27 | | Block 6 | \$0.03018 | (\$0.00836) | (\$0.01656) | \$0.00000 | (\$0.02492) |
| 28 | 32 Trans Firm | Block 1 | \$0.00459 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 29 | | Block 2 | \$0.00393 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 30 | | Block 3 | \$0.00283 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 31 | | Block 4 | \$0.00172 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 32 | | Block 5 | \$0.00106 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 33 | | Block 6 | \$0.00062 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 34 | 32C Sales Interr | Block 1 | \$0.02154 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 35 | | Block 2 | \$0.02093 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 36 | | Block 3 | \$0.01992 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 37 | | Block 4 | \$0.01890 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 38 | | Block 5 | \$0.01829 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 39 | | Block 6 | \$0.01773 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 40 | 32I Sales Interr | Block 1 | \$0.02161 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 41 | | Block 2 | \$0.02101 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 42 | | Block 3 | \$0.02001 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 43 | | Block 4 | \$0.01901 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 44 | | Block 5 | \$0.01841 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 45 | | Block 6 | \$0.01788 | (\$0.00836) | \$0.00000 | (\$0.00197) | (\$0.01033) |
| 46 | 32 Trans Interr | Block 1 | \$0.00384 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 47 | | Block 2 | \$0.00329 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 48 | | Block 3 | \$0.00237 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 49 | | Block 4 | \$0.00146 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 50 | | Block 5 | \$0.00090 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 51 | | Block 6 | \$0.00054 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |
| 52 | 33 | | \$0.00024 | \$0.00000 | \$0.00000 | \$0.00000 | \$0.00000 |

NW Natural
Rates and Regulatory Affairs
2017-2018 PGA Filing - OREGON
Basis for Revenue Related Costs

| | Twelve Months <u>Ended 06/30/17</u> | | |
|----|--|-------------------|------------------------------------|
| 1 | | | |
| 2 | | | |
| 3 | Total Billed Gas Sales Revenues | \$ 674,696,212 | |
| 4 | Total Oregon Revenues | \$ 678,088,466 | |
| 5 | | | |
| 6 | Regulatory Commission Fees [1] | n/a | 0.300% Statutory rate |
| 7 | City License and Franchise Fees | \$ 16,069,889 | 2.370% Line 7 ÷ Line 4 |
| 8 | Net Uncollectible Expense [2] | <u>\$ 848,945</u> | <u>0.125% Line 8 ÷ Line 4</u> |
| 9 | | | |
| 10 | Total | | <u><u>2.795%</u></u> Sum lines 8-9 |
| 11 | | | |
| 12 | | | |

13 **Note:**

14 [1] Dollar figure is set at statutory level of 0.275% times Total Oregon Revenues (line 4).

15 Because the fee changed occurred mid gas year, the difference between the previous fee of 0.275%
 16 and the new fee of 0.3% is being captured as a temporary deferral.

17 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2017-2018 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Tariff Advice 17-12: PGA Gas Costs and Gas Cost Deferrals

| | <u>Including Revenue Sensitive Amount</u> |
|----|--|
| 1 | |
| 2 | |
| 3 | |
| 4 | |
| 5 | |
| 6 | |
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| 8 | |
| 9 | |
| 10 | |
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| 19 | |
| 20 | |
| 21 | |
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| 25 | |
| 26 | |
| 27 | |

Purchased Gas Cost Adjustment (PGA)

Commodity Cost Change (\$11,344,389)

Demand Capacity Cost Change (1,370,387)

Total Gas Cost Change (12,714,776)

Temporary Increments

Removal of Current Temporary Increments

Amortization of 191.xxx Account Gas Costs 408,763

Addition of Proposed Temporary Increments

Amortization of 191.xxx Account Gas Costs (15,624,355)

Net Temporary Rate Adjustment (15,215,592)

TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES (\$27,930,368)

2016 Oregon Earnings Test Normalized Total Revenues \$645,156,000

Effect of this filing, as a percentage change (line 21 ÷ line 25) -4.33%

Company: Northwest Natural Gas Company
 State: Oregon
 Description: Core Market Commodity gas cost deferral
 Account Number: 191400
 Docket UJM 1496
 Last deferral reauthorization was approved in Order 16-384

Narrative: Deferral of customer's share of the difference between actual core commodity cost incurred and the Annual Sales WACOG embedded in customer rates. From Nov 2015 - Oct 2016 the deferral election was 80%. Effective Nov 2016 the deferral election is 90%.

| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 | |
|---------------|----------|------------|----------|--------------------|--------------------|------------------|--------------|---------------|---------------|-------------|-----------------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|------|------|------|------|------|------|------|------|------|------|------|------|--|
| Debit | (Credit) | Month/Year | Note | Commodity Deferral | Storage Adjustment | Hedge Adjustment | Interest | Interest Rate | Transfer | Activity | Balance | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) | (p) | (q) | (r) | (s) | (t) | (u) | (v) | (w) | (x) | (y) | (z) | (aa) | (ab) | (ac) | (ad) | (ae) | (af) | (ag) | (ah) | (ai) | (aj) | (ak) | (al) | |
| Beginning Bal | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 113 | | Oct-15 | | (1,186,996.00) | (3,009.00) | (14,241.00) | (121,762.23) | 7.78% | | | (19,504,692.50) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 114 | | Nov-15 | 1 | (1,134,028.54) | (15,740.21) | (4,661.05) | (34,369.45) | 7.78% | 260.53 | 13,591,908 | (5,912,784.13) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 115 | | Dec-15 | | (2,937,780.12) | (18,896.55) | (12,887.96) | (47,960.89) | 7.78% | 14,780,707.62 | (3,017,526) | (8,930,309.67) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 116 | | Jan-16 | | (3,013,129.51) | (19,337.43) | (26,200.52) | (67,813.35) | 7.78% | | (3,126,481) | (12,056,790.48) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 117 | | Feb-16 | | (3,079,041.43) | (13,756.73) | (21,100.21) | (88,262.41) | 7.78% | | (3,202,161) | (15,258,951.26) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 118 | | Mar-16 | | (4,448,261.52) | (13,194.02) | (15,054.10) | (113,440.22) | 7.78% | | (4,589,950) | (19,848,901.11) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 119 | | Apr-16 | | (1,647,135.91) | (7,236.68) | (9,958.41) | (134,082.25) | 7.78% | | (1,798,413) | (21,647,314.36) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 120 | | May-16 | | (1,500,368.02) | (5,435.76) | (11,935.80) | (145,266.76) | 7.78% | | (1,663,006) | (23,310,320.69) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 121 | | Jun-16 | 1 | (485,300.48) | (4,243.36) | (4,894.48) | (43,489.99) | 7.78% | 16,849,573.00 | 16,311,645 | (6,998,676.01) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 122 | | Jul-16 | | (87,714.81) | (3,888.24) | (4,533.96) | (45,686.39) | 7.78% | | (141,823) | (7,140,499.41) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 123 | | Aug-16 | | (178,977.42) | (3,650.66) | (5,183.30) | (46,903.06) | 7.78% | | (234,714) | (7,375,213.86) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 124 | | Sep-16 | | (38,345.85) | (4,583.07) | (3,276.08) | (47,965.75) | 7.78% | | (94,171) | (7,469,384.61) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 125 | | Oct-16 | 2 | (997,814.36) | (8,392.74) | (6,317.57) | (51,708.79) | 7.78% | (1.63) | (1,064,235) | (8,533,619.69) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 126 | | Nov-16 | 1 | (700,831.39) | (3,462.14) | (19,907.80) | (10,979.06) | 7.778% | 7,181,949.22 | 6,486,584 | (2,047,035.27) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 127 | | Dec-16 | | 1,622,359.46 | (7,117.85) | (14,507.40) | (8,080.49) | 7.778% | | 1,592,654 | (454,381.54) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 128 | | Jan-17 | | 714,538.28 | (8,201.73) | (16,294.00) | (708.84) | 7.778% | | 689,334 | 234,952.16 | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 129 | | Feb-17 | | (2,175,707.56) | (5,609.16) | (1,202.60) | (5,550.30) | 7.778% | | (2,188,070) | (1,953,117.45) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 130 | | Mar-17 | | (2,947,035.53) | (4,705.65) | 9,467.00 | (22,194.88) | 7.778% | | (2,964,469) | (4,917,586.50) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 131 | | Apr-17 | | (1,703,279.38) | (3,379.07) | (259.80) | (37,405.99) | 7.778% | | (1,744,324) | (6,661,910.74) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 132 | | May-17 | | (221,606.13) | (2,064.18) | (2,417.30) | (43,913.00) | 7.778% | | (270,001) | (6,931,911.35) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 133 | | Jun-17 | | 405,864.95 | (1,427.06) | 10.80 | (43,619.59) | 7.778% | | 360,829 | (6,571,082.25) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 134 | | Jul-17 | | | | | (42,591.56) | 7.778% | | (42,592) | (6,613,673.81) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 135 | | Aug-17 | | | | | (42,867.63) | 7.778% | | (42,868) | (6,656,541.44) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 136 | | Sep-17 | | | | | (43,145.48) | 7.778% | | (43,145) | (6,699,686.92) | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 137 | | Oct-17 | | | | | (43,425.14) | 7.778% | | (43,425) | (6,743,112.06) | | | | | | | | | | | | | | | | | | | | | | | | | | | |

History truncated for ease of viewing

NOTES:

1 - Transferred June balance plus July-October interest on June balance to account 191401 for amortization.

2 - Transfer represents true-up of balance to the general ledger.

Company: Northwest Natural Gas Company
 State: Oregon
 Description: Amortization of Oregon WACOG Deferral
 Account Number: 191401
 Dockets UM 1496 and UG 313
 Amortization of 2015-16 deferral approved in Order No. 16-403

| Debit (Credit) | Month/Year | Note | Amortization | Transfers | Interest | Interest rate | Activity | Balance |
|----------------|----------------------|------|---------------|-----------------|-------------|---------------|-----------------|-----------------|
| | (a) | (b) | (c) | (d) | (e) | (e2) | (f) | (g) |
| 7 | Beginning Balance | | | | | | | |
| 122 | Oct-15 | | (871,903) | | 5,417 | 1.77% | (866,486) | 3,242,178.31 |
| 123 | Nov-15 old rates | | (583,314.79) | | 4,352.02 | 1.77% | (578,962.77) | 2,663,215.54 |
| 124 | Nov-15 new rates (1) | | 477,098.53 | (14,043,711.50) | (22,203.30) | 1.93% | (13,588,816.27) | (10,925,600.73) |
| 125 | Dec-15 | | 1,702,692.31 | | (16,202.76) | 1.93% | 1,686,489.55 | (9,239,111.19) |
| 126 | Jan-16 | | 1,993,147.81 | | (13,256.75) | 1.93% | 1,979,891.06 | (7,259,220.12) |
| 127 | Feb-16 | | 1,358,223.17 | | (10,583.01) | 1.93% | 1,347,640.16 | (5,911,579.94) |
| 128 | Mar-16 | | 1,201,786.20 | | (8,541.35) | 1.93% | 1,193,244.85 | (4,718,335.07) |
| 129 | Apr-16 | | 895,596.97 | | (6,868.45) | 1.93% | 888,728.52 | (3,829,606.51) |
| 130 | May-16 | | 587,552.33 | | (5,686.79) | 1.93% | 581,865.54 | (3,247,741.05) |
| 131 | Jun-16 | | 16,788,580.08 | (16,849,573.00) | (18,822.36) | 1.93% | (79,815.28) | (3,327,556.63) |
| 132 | Jul-16 | | 865,947.11 | | (4,655.45) | 1.93% | 861,291.66 | (2,466,264.97) |
| 133 | Aug-16 | | 361,503.02 | | (3,675.87) | 1.93% | 357,827.15 | (2,108,437.82) |
| 134 | Sep-16 | | 390,507.19 | | (3,077.04) | 1.93% | 387,430.15 | (1,721,007.67) |
| 135 | Oct-16 | | 574,454.60 | | (2,306.00) | 1.93% | 572,148.60 | (1,148,859.07) |
| 136 | Nov-16 old rates | | 407,940.78 | | (1,519.70) | 1.93% | 406,421.08 | (742,437.99) |
| 137 | Nov-16 new rates (1) | | 293,121.40 | (7,181,949.22) | (12,898.21) | 2.20% | (6,901,726.03) | (7,644,164.02) |
| 138 | Dec-16 | | 1,227,993.12 | | (12,888.64) | 2.20% | 1,215,104.48 | (6,429,059.54) |
| 139 | Jan-17 | | 1,916,111.24 | | (10,030.17) | 2.20% | 1,906,081.07 | (4,522,978.47) |
| 140 | Feb-17 | | 1,489,288.11 | | (6,926.95) | 2.20% | 1,482,361.16 | (3,040,617.32) |
| 141 | Mar-17 | | 1,167,276.60 | | (4,504.46) | 2.20% | 1,162,772.14 | (1,877,845.18) |
| 142 | Apr-17 | | 865,692.26 | | (2,649.16) | 2.20% | 863,043.10 | (1,014,802.08) |
| 143 | May-17 | 2 | 646,824.22 | 1.13 | (1,267.55) | 2.20% | 645,557.80 | (369,244.28) |
| 144 | Jun-17 | | 398,199.38 | | (311.93) | 2.20% | 397,887.45 | 28,643.17 |
| 145 | Jul-17 Forecast | | 279,838.64 | | 309.03 | 2.20% | 280,147.67 | 308,790.84 |
| 146 | Aug-17 Forecast | | 278,216.12 | | 821.15 | 2.20% | 279,037.27 | 587,828.11 |
| 147 | Sep-17 Forecast | | 298,092.04 | | 1,350.94 | 2.20% | 299,442.98 | 887,271.09 |
| 148 | Oct-17 Forecast | | 590,108.34 | | 2,167.60 | 2.20% | 592,275.94 | 1,479,547.03 |

History truncated for ease of viewing

NOTES:

- 1 - Transferred in authorized balance from accounts 191400 and 191405.
- 2 - Transfer represents a true-up to the general ledger.

Company: Northwest Natural Gas Company
 State: Oregon
 Description: Core Market Demand cost deferral
 Account Number: 191410
 Docket UM 1496
 Last deferral reauthorization was approved in Order 16-384

Narrative: Deferral of 100% of the difference between actual demand cost incurred and the demand cost embedded in customer rates.

| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 | 24 | 25 | 26 | 27 | 28 | 29 | 30 | 31 | 32 | 33 | 34 | 35 | 36 | 37 | 38 |
|---------------|----------|------------|------|-----------------|--------------|-------------|---------------|--------------|----------------|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|----|
| Debit | (Credit) | Month/Year | Note | Demand Deferral | Transfer | Interest | Interest Rate | Activity | Balance | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| (a) | (b) | (c) | (d) | (e1) | (e2) | (f) | (g) | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Beginning Bal | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 113 | | Oct-15 | | (380,876.04) | | (35,045.76) | 7.78% | (415,921.72) | (5,630,999.52) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 114 | | Nov-15 | 1 | 284,630.66 | 4,414,662.82 | (6,963.24) | 7.78% | 4,692,330.32 | (938,669.20) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 115 | | Dec-15 | | (169,707.02) | | (6,635.84) | 7.78% | (176,342.78) | (1,115,011.98) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 116 | | Jan-16 | | (7,176.90) | | (7,252.26) | 7.78% | (14,429.08) | (1,129,441.06) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 117 | | Feb-16 | | (50,813.26) | | (7,487.26) | 7.78% | (58,300.44) | (1,187,741.50) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 118 | | Mar-16 | | (15,389.83) | | (7,750.41) | 7.78% | (23,140.16) | (1,210,881.67) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 119 | | Apr-16 | | (127,150.65) | | (8,262.73) | 7.78% | (135,413.30) | (1,346,294.97) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 120 | | May-16 | | 501,494.76 | | (7,102.80) | 7.78% | 494,392.04 | (851,902.93) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 121 | | Jun-16 | | (450,555.03) | | (6,983.72) | 7.78% | (457,538.67) | (1,309,441.60) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 122 | | Jul-16 | | (16,512.87) | | (8,543.08) | 7.78% | (25,055.87) | (1,334,497.47) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 123 | | Aug-16 | | (9,432.85) | | (8,682.57) | 7.78% | (18,115.34) | (1,352,612.81) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 124 | | Sep-16 | | (11,796.45) | | (8,807.68) | 7.78% | (20,604.05) | (1,373,216.87) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 125 | | Oct-16 | 2 | 8,712.56 | (1.14) | (8,874.79) | 7.78% | (163.29) | (1,373,380.16) | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 126 | | Nov-16 | 1 | 65,712.39840 | 1,343,731.46 | 20.79 | 7.778% | 1,409,464.65 | 36,084.49020 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 127 | | Dec-16 | | 11,395.03 | | 270.82 | 7.778% | 11,665.85 | 47,750.34 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 128 | | Jan-17 | | (31,117.10) | | 208.66 | 7.778% | (30,908.44) | 16,841.90 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 129 | | Feb-17 | | 161,358.86 | | 632.10 | 7.778% | 161,990.96 | 178,832.86 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 130 | | Mar-17 | | 88,426.17 | | 1,445.71 | 7.778% | 89,871.88 | 268,704.74 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 131 | | Apr-17 | | 65,552.63 | | 1,954.10 | 7.778% | 67,506.73 | 336,211.46 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 132 | | May-17 | | 47,370.84 | | 2,332.73 | 7.778% | 49,703.57 | 385,915.03 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 133 | | Jun-17 | | (59,805.29) | | 2,307.55 | 7.778% | (57,497.74) | 328,417.29 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 134 | | Jul-17 | | | | 2,128.69 | 7.778% | 2,128.69 | 330,545.98 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 135 | | Aug-17 | | | | 2,142.49 | 7.778% | 2,142.49 | 332,688.47 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 136 | | Sep-17 | | | | 2,156.38 | 7.778% | 2,156.38 | 334,844.85 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |
| 137 | | Oct-17 | | | | 2,170.35 | 7.778% | 2,170.35 | 337,015.20 | | | | | | | | | | | | | | | | | | | | | | | | | | | | |

History truncated for ease of viewing

NOTES

1 -Transferred June balance plus July-October interest on June balance to account 191411 for amortization.

2 -Transfer represents true-up to general ledger.

Company: Northwest Natural Gas Company
 State: Oregon
 Description: Amortization of Oregon Demand Deferral
 Account Number: 191411
 Dockets UM 1496 and UG 313
 Amortization of 2015-16 deferral approved in Order No. 16-403

| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | |
|----------------|-------------------|---------------|----------------|--------------|------------|---------------|----------------|----------------|----|----|----|----|----|----|----|----|----|----|----|--|
| Debit (Credit) | Month/Year | Note | Amortization | Transfers | Interest | Interest Rate | Activity | Balance | | | | | | | | | | | | |
| | (a) | (b) | (c) | (d) | (e1) | (e2) | (f) | (g) | | | | | | | | | | | | |
| 7 | Beginning Balance | | | | | | | | | | | | | | | | | | | |
| 122 | Oct-15 | | 185,752 | (0) | (1,412) | 1.77% | 184,340 | (865,769.78) | | | | | | | | | | | | |
| 123 | Nov-15 | old rates | 137,180.72 | | (1,175.84) | 1.77% | 136,004.88 | (729,765.76) | | | | | | | | | | | | |
| 124 | Nov-15 | new rates (1) | (344,103.54) | 9,756,304.40 | 15,414.67 | 1.93% | 9,427,615.53 | 8,697,849.77 | | | | | | | | | | | | |
| 125 | Dec-15 | | (1,360,659.75) | | 12,894.84 | 1.93% | (1,347,764.91) | 7,350,084.86 | | | | | | | | | | | | |
| 126 | Jan-16 | | (1,603,178.16) | | 10,532.16 | 1.93% | (1,592,646.00) | 5,757,438.87 | | | | | | | | | | | | |
| 127 | Feb-16 | | (1,076,585.12) | | 8,394.13 | 1.93% | (1,068,190.99) | 4,689,247.88 | | | | | | | | | | | | |
| 128 | Mar-16 | | (942,161.32) | | 6,784.22 | 1.93% | (935,377.10) | 3,753,870.78 | | | | | | | | | | | | |
| 129 | Apr-16 | | (694,689.49) | | 5,478.83 | 1.93% | (689,210.66) | 3,064,660.12 | | | | | | | | | | | | |
| 130 | May-16 | | (439,870.80) | | 4,575.27 | 1.93% | (435,295.53) | 2,629,364.59 | | | | | | | | | | | | |
| 131 | Jun-16 | | (366,439.18) | | 3,934.22 | 1.93% | (362,504.96) | 2,266,859.63 | | | | | | | | | | | | |
| 132 | Jul-16 | | (293,350.53) | | 3,409.96 | 1.93% | (289,940.57) | 1,976,919.06 | | | | | | | | | | | | |
| 133 | Aug-16 | | (255,085.80) | | 2,974.41 | 1.93% | (252,111.39) | 1,724,807.67 | | | | | | | | | | | | |
| 134 | Sep-16 | | (279,303.76) | | 2,549.46 | 1.93% | (276,754.30) | 1,448,053.37 | | | | | | | | | | | | |
| 135 | Oct-16 | | (424,016.66) | | 1,987.97 | 1.93% | (422,028.69) | 1,026,024.68 | | | | | | | | | | | | |
| 136 | Nov-16 | old rates | (343,420.93) | | 1,374.02 | 1.93% | (342,046.91) | 683,977.77 | | | | | | | | | | | | |
| 137 | Nov-16 | new rates (1) | (252,067.75) | 7,330,925.04 | 13,208.97 | 2.20% | 7,092,066.26 | 7,776,044.03 | | | | | | | | | | | | |
| 138 | Dec-16 | | (1,203,661.71) | | 13,152.72 | 2.20% | (1,190,508.99) | 6,585,535.05 | | | | | | | | | | | | |
| 139 | Jan-17 | | (1,907,657.53) | | 10,324.79 | 2.20% | (1,897,332.74) | 4,688,202.30 | | | | | | | | | | | | |
| 140 | Feb-17 | | (1,476,251.99) | | 7,241.81 | 2.20% | (1,469,010.18) | 3,219,192.12 | | | | | | | | | | | | |
| 141 | Mar-17 | | (1,140,964.20) | | 4,855.97 | 2.20% | (1,136,108.23) | 2,083,083.89 | | | | | | | | | | | | |
| 142 | Apr-17 | | (837,211.73) | | 3,051.54 | 2.20% | (834,160.19) | 1,248,923.69 | | | | | | | | | | | | |
| 143 | May-17 | | (615,963.49) | | 1,725.06 | 2.20% | (614,238.43) | 634,685.26 | | | | | | | | | | | | |
| 144 | Jun-17 | | (366,341.19) | | 827.78 | 2.20% | (365,513.41) | 269,171.85 | | | | | | | | | | | | |
| 145 | Jul-17 | Forecast | (250,620.59) | | 263.75 | 2.20% | (250,356.84) | 18,815.01 | | | | | | | | | | | | |
| 146 | Aug-17 | Forecast | (249,782.90) | | (194.47) | 2.20% | (249,977.37) | (231,162.36) | | | | | | | | | | | | |
| 147 | Sep-17 | Forecast | (267,797.27) | | (669.28) | 2.20% | (268,466.55) | (499,628.91) | | | | | | | | | | | | |
| 148 | Oct-17 | Forecast | (562,656.54) | | (1,431.75) | 2.20% | (564,088.29) | (1,063,717.20) | | | | | | | | | | | | |

History truncated for ease of viewing

NOTES:

1 - Transferred in authorized balances from accounts 191410, 191450, and 191417.

Company: Northwest Natural Gas Company
 State: Oregon
 Description: Coos County Demand
 Account Number: 191417
 Docket UM 1179 Order 04-702 3

Narrative: Deferral of transportation charge payable by NW Natural for use of the natural gas transmission pipeline owned by Coos County.

| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | | | | |
|-------|---------------|------------|------|-----------|-------------|--------------|----------|--------------|------------|-----|-----|-----|-----|-----|-----|-----|-----|
| Debit | (Credit) | Month/Year | Note | Deferral | Adjustment | Transfer | Interest | Activity | Balance | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) |
| 6 | Beginning Bal | | | | | | | | | | | | | | | | |
| 113 | | Oct-15 | | 16,636.00 | (6,090.02) | | | 10,545.98 | 145,856.20 | | | | | | | | |
| 114 | | Nov-15 | 1 | 16,636.00 | (4,786.01) | (101,600.27) | | (89,750.28) | 56,105.92 | | | | | | | | |
| 115 | | Dec-15 | | 16,636.00 | (6,714.01) | | | 9,921.99 | 66,027.91 | | | | | | | | |
| 116 | | Jan-16 | | 16,636.00 | (8,610.72) | | | 8,025.28 | 74,053.19 | | | | | | | | |
| 117 | | Feb-16 | 2 | 16,635.00 | (23,472.11) | | | (6,837.11) | 67,216.08 | | | | | | | | |
| 118 | | Mar-16 | | 16,637.17 | (6,572.87) | | | 10,064.30 | 77,280.38 | | | | | | | | |
| 119 | | Apr-16 | | 16,635.00 | (5,211.62) | | | 11,423.38 | 88,703.76 | | | | | | | | |
| 120 | | May-16 | | 16,635.00 | (4,468.13) | | | 12,166.87 | 100,870.63 | | | | | | | | |
| 121 | | Jun-16 | | 16,635.00 | (4,167.18) | | | 12,467.82 | 113,338.45 | | | | | | | | |
| 122 | | Jul-16 | | 16,635.00 | (4,093.51) | | | 12,541.49 | 125,879.94 | | | | | | | | |
| 123 | | Aug-16 | | 16,635.00 | (4,023.57) | | | 12,611.43 | 138,491.37 | | | | | | | | |
| 124 | | Sep-16 | | 16,635.00 | (3,459.90) | | | 13,175.10 | 151,666.47 | | | | | | | | |
| 125 | | Oct-16 | | 16,635.00 | (4,980.33) | | | 11,654.67 | 163,321.14 | | | | | | | | |
| 126 | | Nov-16 | 1 | 16,635.00 | (5,148.76) | (113,338.45) | | (101,852.21) | 61,468.93 | | | | | | | | |
| 127 | | Dec-16 | | 16,635.00 | (8,564.61) | | | 8,070.39 | 69,539.31 | | | | | | | | |
| 128 | | Jan-17 | | 16,635.00 | (11,302.20) | | | 5,332.80 | 74,872.11 | | | | | | | | |
| 129 | | Feb-17 | | 23,783.00 | (7,671.01) | | | 16,111.99 | 90,984.10 | | | | | | | | |
| 130 | | Mar-17 | | 23,783.00 | (8,991.09) | | | 14,791.91 | 105,776.01 | | | | | | | | |
| 131 | | Apr-17 | | 23,783.00 | (6,685.68) | | | 17,097.32 | 122,873.33 | | | | | | | | |
| 132 | | May-17 | 2 | 23,783.00 | 78,824.62 | | | 102,607.62 | 225,480.95 | | | | | | | | |
| 133 | | Jun-17 | | 23,783.00 | (4,586.06) | | | 19,196.94 | 244,677.89 | | | | | | | | |
| 134 | | Jul-17 | | | | | | 0.00 | 244,677.89 | | | | | | | | |
| 135 | | Aug-17 | | | | | | 0.00 | 244,677.89 | | | | | | | | |
| 136 | | Sep-17 | | | | | | 0.00 | 244,677.89 | | | | | | | | |
| 137 | | Oct-17 | | | | | | 0.00 | 244,677.89 | | | | | | | | |

History truncated for ease of viewing

NOTES

- 1 - June balance transferred to account 191411 for amortization.
- 2 - Includes approx. \$85K true-up of previous year's demand charges based on actual 2016 costs.
- 3 - As a condition of the Coos Bay Stipulation in UG- 152, the company agreed to annually evaluate the Coos County Charge to determine whether it is fully recovering NW Natural's cost of transportation on the County pipeline. For the current period, based on loads from Coos County customers, the charge is not fully recovering transportation costs.

Company: Northwest Natural Gas Company
 State: Oregon
 Description: Seasonalized Demand Collection Deferral
 Account Number: 191450
 Docket UM 1496
 Last deferral reauthorization was approved in Order 16-384

Narrative: Deferral of 100% of the difference between actual demand costs collected and the seasonalized imbedded demand costs embedded in customer rates.

| 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 |
|---------------|----------|------------|----------|-----------------|-------------|---------------|-----------------|-----------------|----------------|-----|-----|-----|-----|
| Debit | (Credit) | Month/Year | Note | Demand Deferral | Interest | Interest Rate | Transfer | Activity | Balance | (a) | (b) | (c) | (d) |
| | | | | (d) | (e) | (f) | (g) | (i) | (j) | | | | |
| Beginning Bal | | | | | | | | | | | | | |
| 113 | | Oct-15 | | 1,628,087.06 | 94,183.34 | 7.78% | | 1,722,270.48 | 15,435,219.65 | | | | |
| 114 | | Nov-15 | 1 | (479,675.83) | 7,300.33 | 7.78% | (14,069,366.95) | (14,541,742.36) | 893,477.28 | | | | |
| 115 | | Dec-15 | | 1,355,017.05 | 10,185.22 | 7.78% | | 1,365,202.34 | 2,258,679.63 | | | | |
| 116 | | Jan-16 | | 451,529.59 | 16,107.48 | 7.78% | | 467,637.15 | 2,726,316.77 | | | | |
| 117 | | Feb-16 | | 1,790,612.47 | 23,480.19 | 7.78% | | 1,814,092.74 | 4,540,409.51 | | | | |
| 118 | | Mar-16 | | 721,136.36 | 31,774.67 | 7.78% | | 752,911.11 | 5,293,320.62 | | | | |
| 119 | | Apr-16 | | 1,974,641.73 | 40,719.49 | 7.78% | | 2,015,361.29 | 7,308,681.91 | | | | |
| 120 | | May-16 | | 880,686.27 | 50,239.51 | 7.78% | | 930,925.86 | 8,239,607.77 | | | | |
| 121 | | Jun-16 | 2 | 49,664.48 | 53,581.08 | 7.78% | (6.39) | 103,239.25 | 8,342,847.02 | | | | |
| 122 | | Jul-16 | | (66,671.33) | 53,873.33 | 7.78% | | (12,797.92) | 8,330,049.10 | | | | |
| 123 | | Aug-16 | | 42,955.67 | 54,145.73 | 7.78% | | 97,101.48 | 8,427,150.58 | | | | |
| 124 | | Sep-16 | | (356,208.92) | 53,481.32 | 7.78% | | (302,727.52) | 8,124,423.05 | | | | |
| 125 | | Oct-16 | 2 | 204,947.24 | 53,337.71 | 7.78% | (0.32) | 258,284.71 | 8,382,707.76 | | | | |
| 126 | | Nov-16 | 1 | 1,582,936.75 | 3,972.34 | 7.778% | (8,561,318.05) | (6,974,408.96) | 1,408,298.80 | | | | |
| 127 | | Dec-16 | | (1,987,604.89) | 2,686.63 | 7.778% | | (1,984,918.26) | (576,619.47) | | | | |
| 128 | | Jan-17 | | (4,570,905.39) | (18,551.00) | 7.778% | | (4,589,456.39) | (5,166,075.85) | | | | |
| 129 | | Feb-17 | | (1,682,967.13) | (38,939.00) | 7.778% | | (1,721,906.13) | (6,887,981.98) | | | | |
| 130 | | Mar-17 | | (1,152,976.62) | (48,382.21) | 7.778% | | (1,201,358.83) | (8,089,340.81) | | | | |
| 131 | | Apr-17 | | (879,886.56) | (55,283.98) | 7.778% | | (935,170.54) | (9,024,511.35) | | | | |
| 132 | | May-17 | | 41,412.96 | (58,359.66) | 7.778% | | (16,946.70) | (9,041,458.05) | | | | |
| 133 | | Jun-17 | | 87,645.12 | (58,319.67) | 7.778% | | 29,325.45 | (9,012,132.60) | | | | |
| 134 | | Jul-17 | | | (58,413.64) | 7.778% | | (58,413.64) | (9,070,546.24) | | | | |
| 135 | | Aug-17 | | | (58,792.26) | 7.778% | | (58,792.26) | (9,129,338.50) | | | | |
| 136 | | Sep-17 | | | (59,173.33) | 7.778% | | (59,173.33) | (9,188,511.83) | | | | |
| 137 | | Oct-17 | | | (59,556.87) | 7.778% | | (59,556.87) | (9,248,068.70) | | | | |

History truncated for ease of viewing

NOTES

- 1** -Transferred June balance plus July-October interest on June balance to account 191411 for amortization.
- 2** -Transfer represents true-up to general ledger.

EXHIBIT B

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 17-12 / UG 334

July 28, 2017

NW NATURAL

EXHIBIT B

Supporting Materials

Purchased Gas Cost

NWN OPUC ADVICE NO. 17-12 / UG 334

| Commodity and Non-Commodity Costs | Page |
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| Summary of Total Commodity Cost | 1 |
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| Derivation of Oregon Per Therm Non-Commodity Charges | 4 |
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NW Natural
 2017-2018 PGA - SYSTEM: August Filing
 Summary of Total Commodity Cost
 ALL VOLUMES IN THERMS

| | (a) | (b) | (c) | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | (d) |
|----|---|-----|-----|--------------|--------------|--------------|--------------|--------------|--------------|--------------|-------------|-------------|-------------|-------------|--------------|---------------|
| | | | | November | December | January | February | March | April | May | June | July | August | September | October | TOTAL |
| 1 | SYSTEM COSTS | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | | | | | |
| 4 | COSTS | | | | | | | | | | | | | | | |
| 5 | Commodity Cost from Supply | | | | | | | | | | | | | | | |
| 6 | tab commodity cost from supply, column c.d, lines 93-104 plus | | | \$19,743,617 | \$22,182,379 | \$20,782,994 | \$13,015,847 | \$15,224,058 | \$10,682,756 | \$7,497,483 | \$5,198,527 | \$4,417,664 | \$4,363,319 | \$5,018,145 | \$9,268,339 | \$137,395,128 |
| 7 | tab commodity cost from gas reserve, column q, lines 59-70 | | | | | | | | | | | | | | | |
| 8 | Volumetric Pipeline Chgs | | | | | | | | | | | | | | | |
| 9 | tab commodity cost from supply, column c.d, lines 93-104 plus | | | \$264,995 | \$295,270 | \$93,387 | \$67,762 | \$71,959 | \$56,737 | \$41,058 | \$29,834 | \$26,182 | \$25,893 | \$28,596 | \$49,334 | \$1,051,007 |
| 10 | Commodity Cost from Storage | | | | | | | | | | | | | | | |
| 11 | tab commodity cost from vol pipe, column e, line 78-89 | | | \$479,216 | \$11,073,790 | \$11,063,469 | \$12,617,945 | \$5,260,183 | \$99,894 | \$103,224 | \$99,894 | \$103,224 | \$103,224 | \$99,894 | \$103,224 | \$41,197,181 |
| 12 | Commodity Cost from Gas Reserves | | | | | | | | | | | | | | | |
| 13 | tab Commodity Cost from Storage, column k, line 61-72 | | | \$2,588,818 | \$2,619,972 | \$2,582,628 | \$2,385,816 | \$2,514,894 | \$2,429,122 | \$2,485,055 | \$2,382,680 | \$2,374,695 | \$2,348,847 | \$2,275,179 | \$2,299,736 | \$29,287,442 |
| 14 | tab Commodity Cost from Gas Reserve, column p, line 59-70 | | | | | | | | | | | | | | | |
| 15 | Total Commodity Cost | | | \$23,076,646 | \$36,171,411 | \$34,512,477 | \$28,087,370 | \$23,071,094 | \$13,268,508 | \$10,126,821 | \$7,710,935 | \$6,921,765 | \$6,841,284 | \$7,421,814 | \$11,720,633 | \$208,930,758 |
| 16 | VOLUMES | | | | | | | | | | | | | | | |
| 17 | Commodity Volumes at Receipt Points | | | | | | | | | | | | | | | |
| 18 | Pipeline Fuel Use | | | 82,000,274 | 84,830,240 | 80,424,791 | 52,346,477 | 63,358,318 | 58,051,653 | 41,103,552 | 29,174,468 | 25,172,609 | 24,863,385 | 27,874,255 | 50,031,824 | 619,231,847 |
| 19 | Gas Arriving at City Gate | | | 2,144,066 | 2,218,390 | 2,088,209 | 1,338,493 | 1,641,570 | 1,661,076 | 1,097,812 | 749,076 | 630,169 | 621,031 | 735,780 | 1,422,279 | 16,347,949 |
| 20 | Storage Gas Withdrawals | | | 79,856,208 | 82,611,850 | 78,336,583 | 51,007,984 | 61,716,748 | 56,390,577 | 40,005,740 | 28,425,392 | 24,542,440 | 24,242,354 | 27,138,476 | 48,609,546 | 602,883,898 |
| 21 | Pipeline Fuel Use for Off-site Storage | | | 1,811,488 | 35,531,622 | 35,047,736 | 40,395,589 | 16,535,504 | 240,000 | 248,000 | 240,000 | 248,000 | 248,000 | 240,000 | 248,000 | 131,033,938 |
| 22 | Storage Gas Deliveries at City Gate | | | 50,904 | 211,986 | 179,139 | 201,998 | 73,751 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 717,778 |
| 23 | Total Gas At City Gate (Storage and Commodity) | | | 1,760,584 | 35,319,635 | 34,868,597 | 40,193,590 | 16,461,753 | 240,000 | 248,000 | 240,000 | 248,000 | 248,000 | 240,000 | 248,000 | 130,316,160 |
| 24 | Unaccounted for Gas | | | 81,616,792 | 117,931,485 | 113,205,180 | 91,201,574 | 78,178,501 | 56,630,577 | 40,253,740 | 28,665,392 | 24,790,440 | 24,490,354 | 27,378,476 | 48,857,546 | 733,200,057 |
| 25 | Load Served | | | 621,552 | 643,000 | 609,724 | 397,015 | 480,366 | 438,910 | 311,380 | 221,246 | 191,023 | 188,688 | 211,229 | 378,347 | 4,692,480 |
| 26 | | | | 80,995,240 | 117,288,485 | 112,595,456 | 90,804,559 | 77,698,135 | 56,191,667 | 39,942,359 | 28,444,147 | 24,599,417 | 24,301,667 | 27,167,246 | 48,479,198 | 728,507,577 |

NW Natural
 2017-2018 PGA - SYSTEM: August Filing
 Summary of Total Demand Charges

SYSTEM COSTS

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) | (k) | (l) | (m) | (n) | (o) |
|--|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|-------------|--------------|-----|-----|
| | November | December | January | February | March | April | May | June | July | August | September | October | TOTAL | | |
| | 30 | 31 | 31 | 28 | 31 | 30 | 31 | 31 | 30 | 31 | 30 | 31 | 31 | 30 | 31 |
| Transport charges by transporter: | | | | | | | | | | | | | | | |
| 1 | | | | | | | | | | | | | | | |
| 2 | | | | | | | | | | | | | | | |
| 3 | | | | | | | | | | | | | | | |
| 4 | | | | | | | | | | | | | | | |
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| 15 | | | | | | | | | | | | | | | |
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| 20 | | | | | | | | | | | | | | | |
| 21 | | | | | | | | | | | | | | | |
| 22 | | | | | | | | | | | | | | | |
| 23 | | | | | | | | | | | | | | | |
| | \$4,400,118 | \$4,546,788 | \$4,359,348 | \$3,937,476 | \$4,359,348 | \$4,123,063 | \$4,260,498 | \$4,123,063 | \$4,260,498 | \$4,260,498 | \$4,123,063 | \$4,232,479 | \$50,986,239 | | |
| | 677,289 | 677,289 | 677,289 | 677,289 | 677,289 | 677,289 | 677,289 | 677,289 | 677,289 | 677,289 | 677,289 | 677,289 | 8,127,471 | | |
| | 275,448 | 275,448 | 275,448 | 275,448 | 275,448 | 245,860 | 245,860 | 245,860 | 245,860 | 245,860 | 245,860 | 275,448 | 3,127,846 | | |
| | 484,979 | 501,145 | 501,145 | 452,647 | 501,145 | 408,140 | 421,745 | 408,140 | 421,745 | 421,745 | 408,140 | 501,145 | 5,431,862 | | |
| | 621,917 | 640,248 | 640,248 | 585,256 | 640,248 | 621,917 | 640,248 | 621,917 | 640,248 | 640,248 | 621,917 | 640,248 | 7,554,660 | | |
| | 313,500 | 323,950 | 323,950 | 292,600 | 323,950 | 313,500 | 323,950 | 313,500 | 323,950 | 323,950 | 313,500 | 323,950 | 3,814,250 | | |
| | 18,688 | 18,688 | 18,688 | 18,688 | 18,688 | 18,688 | 18,688 | 18,688 | 18,688 | 18,688 | 18,688 | 18,688 | 224,258 | | |
| | \$6,791,939 | \$6,983,556 | \$6,796,117 | \$6,239,404 | \$6,796,117 | \$6,408,457 | \$6,588,278 | \$6,408,457 | \$6,588,278 | \$6,588,278 | \$6,408,457 | \$6,669,248 | \$79,266,586 | | |

Detail in file "Capacity Contract Monthly Summary for 2017-18 PGA Year.xls"

NW Natural
 2017-2018 PGA - SYSTEM: August Filing
 Derivation of Oregon per therm Non-Commodity Charges
 ALL VOLUMES IN THERMS

Oregon Derivation of Demand Increments

| | | <u>Without</u> Revenue Sensitive | <u>WITH</u> Revenue Sensitive |
|----|---|-------------------------------------|----------------------------------|
| | (a) (b) | (c) | (d) |
| 1 | | | |
| 2 | | | |
| 3 | | | |
| 4 | System Demand | \$79,266,586 | |
| 5 | Oregon Allocation Factor 1/ | 89.49% | |
| 6 | Oregon Demand | \$70,935,668 | |
| 7 | | | |
| 8 | Oregon Firm Sales Forecasted Normal Volumes | 606,239,575 | |
| 9 | Oregon Interruptible Sales Forecasted Normal Vol | 49,757,635 | |
| 10 | | | |
| 11 | | | |
| 12 | Proposed Firm Demand Per Therm 2/ | \$0.11588 | \$0.11921 |
| 13 | Proposed Interruptible Demand 2/ | \$0.01379 | \$0.01419 |
| 14 | Proposed MDDV Demand Charge | \$1.72 | \$1.77 |
| 15 | | | |
| 16 | Current Firm Demand Per Therm | \$0.11784 | \$0.12132 |
| 17 | Current Interruptible Demand | \$0.01402 | \$0.01443 |
| 18 | Current MDDV Demand Charge | \$1.75 | \$1.80 |
| 19 | | | |
| 20 | Percent Change in Firm Demand | -1.66% | |
| 21 | | | |
| 22 | | | |
| 23 | 1/Allocation Factor: 2016-17 PGA forecast firm sales volumes: | | |
| 24 | | <u>Washington</u> | <u>Oregon</u> |
| 25 | Firm Sales | 71,202,188 | 606,239,575 |
| 26 | | 10.51% | 89.49% |
| 27 | | | <u>System</u> |
| 28 | | | 677,441,763 |
| 29 | | | 100.00% |
| 30 | 2/Calculation of Proposed Demand Rates: | | |
| 31 | | | |
| 32 | Demand change factor | 0.983 | |
| 33 | Firm Demand (line 16 * line 30) | \$0.11588 | \$70,249,682 |
| 34 | Interruptible Demand (line 17 * line 30) | \$0.01379 | \$685,986 |
| | | | <u>\$70,935,668</u> |

NW Natural
 2017-2018 PGA - SYSTEM: August Filing
 Calculation of Winter WACOG
 Prices are per therm

| | | | |
|----|--|---------------------|--------------------|
| 1 | Forecast price for AECO gas: | | |
| 2 | | | |
| 3 | | <u>AECO/NIT</u> | |
| 4 | | | |
| 5 | November | \$0.21533 | |
| 6 | December | \$0.22455 | |
| 7 | January | \$0.23029 | |
| 8 | February | \$0.23160 | |
| 9 | March | \$0.22558 | |
| 10 | April | \$0.18461 | |
| 11 | May | \$0.18141 | |
| 12 | June | \$0.18283 | |
| 13 | July | \$0.18400 | |
| 14 | August | \$0.18449 | |
| 15 | September | \$0.18348 | |
| 16 | October | \$0.18788 | |
| 17 | | | |
| 18 | | | |
| 19 | Average price, November-March | \$0.22547 | average lines 5-9 |
| 20 | | | |
| 21 | Annual average price, November-October | \$0.20134 | average lines 5-16 |
| 22 | | | |
| 23 | Ratio of winter to annual | 1.11985 | line 19 ÷ line 21 |
| 24 | | | |
| 25 | | Without Rev | WITH Rev |
| 26 | | <u>Sensitive</u> | <u>Sensitive</u> |
| OR | Oregon Annual WACOG | \$0.28932 | \$0.29764 |
| OR | Oregon Winter WACOG | \$0.32400 | \$0.33332 |
| | | line 23 * \$0.28932 | |
| WA | Washington Annual WACOG | \$0.26392 | \$0.27599 |
| WA | Washington Winter WACOG | \$0.29555 | \$0.30906 |
| | | line 23 * \$0.26392 | |

NW Natural
 2017-2018 PGA - OREGON: August Filing
 Derivation of Oregon Seasonalized Fixed Charges

| | (a) | (b) | (c) | (d) | (e) | (f) | (g) | (h) | (i) | (j) |
|----|-----------|------|--------------------------------|-------------------------------|-------------------------|-----------------------|-------------|-------------------------------------|--|----------------------------|
| | | | Normalized Residential Volumes | Normalized Commercial Volumes | Firm Industrial Volumes | Interruptible Volumes | Total | Firm Demand Increment Eff. 11/01/17 | Interr. Demand Increment Eff. 11/01/17 | Seasonalized Fixed Charges |
| 6 | November | 2017 | 41,272,940 | 24,641,128 | 2,511,540 | 4,517,030 | 72,942,638 | \$0.11921 | \$0.01419 | \$7,991,273 |
| 7 | December | 2017 | 62,372,487 | 34,829,521 | 3,016,462 | 5,101,005 | 105,319,475 | \$0.11921 | \$0.01419 | \$11,683,396 |
| 8 | January | 2018 | 59,445,591 | 33,229,268 | 3,200,031 | 5,292,507 | 101,167,397 | \$0.11921 | \$0.01419 | \$11,182,715 |
| 9 | February | 2018 | 47,141,315 | 26,950,762 | 2,749,219 | 4,745,189 | 81,586,485 | \$0.11921 | \$0.01419 | \$8,969,606 |
| 10 | March | 2018 | 38,996,902 | 23,526,413 | 2,642,628 | 4,919,898 | 70,085,841 | \$0.11921 | \$0.01419 | \$7,619,109 |
| 11 | April | 2018 | 27,165,131 | 17,054,856 | 2,435,225 | 4,209,131 | 50,864,343 | \$0.11921 | \$0.01419 | \$5,464,333 |
| 12 | May | 2018 | 18,054,946 | 11,939,390 | 2,125,945 | 3,887,276 | 36,007,558 | \$0.11921 | \$0.01419 | \$3,775,627 |
| 13 | June | 2018 | 11,012,786 | 9,230,817 | 1,998,461 | 3,398,842 | 25,640,906 | \$0.11921 | \$0.01419 | \$2,624,229 |
| 14 | July | 2018 | 8,580,234 | 8,399,498 | 2,052,220 | 3,230,161 | 22,262,114 | \$0.11921 | \$0.01419 | \$2,249,924 |
| 15 | August | 2018 | 8,449,642 | 8,326,157 | 2,038,494 | 3,159,452 | 21,973,745 | \$0.11921 | \$0.01419 | \$2,223,727 |
| 16 | September | 2018 | 9,907,736 | 8,857,334 | 2,362,418 | 3,370,829 | 24,498,317 | \$0.11921 | \$0.01419 | \$2,494,689 |
| 17 | October | 2018 | 22,707,722 | 14,461,310 | 2,553,045 | 3,926,313 | 43,648,390 | \$0.11921 | \$0.01419 | \$4,657,040 |
| 18 | | | | | | | | | | |
| 19 | | | | | | | | | | |
| 20 | | | | | | | | | | |
| 21 | | | 355,107,432 | 221,446,453 | 29,685,690 | 49,757,635 | 655,997,209 | | | \$70,935,668 |

| Encana Gas Reserves Deal | Projected November 2017 | Projected December 2017 | Projected January 2018 | Projected February 2018 | Projected March 2018 | Projected April 2018 | Projected May 2018 | Projected June 2018 | Projected July 2018 | Projected August 2018 | Projected September 2018 | Projected October 2018 | Projected PGA Totals |
|-----------------------------------|-------------------------------|-------------------------------|------------------------------|-------------------------------|----------------------------|----------------------------|--------------------------|---------------------------|---------------------------|-----------------------------|--------------------------------|------------------------------|----------------------------|
| | | | | | | | | | | | | | |
| 1 Thermo Delivered (000s) | | | | | | | | | | | | | |
| 2 Total Thermo | 3,825.39 | 3,894.16 | 3,823.78 | 3,404.67 | 3,711.77 | 3,537.53 | 3,606.62 | 3,444.54 | 3,513.57 | 3,471.68 | 3,322.55 | 3,395.78 | 42,952.03 |
| 3 Rate per Therm (Depletion Rate) | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 | 0.35690 |
| 4 Delivery Value | 1,365.27 | 1,389.81 | 1,364.69 | 1,215.12 | 1,324.72 | 1,262.53 | 1,287.19 | 1,229.34 | 1,253.98 | 1,239.03 | 1,185.81 | 1,211.94 | 15,329.42 |
| 5 | | | | | | | | | | | | | 0.3569 |
| 6 Opex / Severance / Ad Valorem | | | | | | | | | | | | | |
| 7 Operating Cost | 512.96 | 516.96 | 514.27 | 496.21 | 515.70 | 521.06 | 560.06 | 529.09 | 498.30 | 496.58 | 490.25 | 493.29 | 6,144.73 |
| 8 Severance and Ad Valorem Taxes | 133.22 | 148.75 | 149.75 | 131.69 | 132.39 | 104.01 | 101.26 | 97.96 | 105.00 | 104.17 | 98.89 | 100.66 | 1,407.75 |
| 9 Total | 646.18 | 665.71 | 664.02 | 627.91 | 648.09 | 625.07 | 661.33 | 627.04 | 603.30 | 600.74 | 589.14 | 593.95 | 7,552.48 |
| 10 | | | | | | | | | | | | | 0.1758 |
| 11 Average Rate Base | 58,715.69 | 57,835.33 | 56,972.67 | 56,200.56 | 55,362.10 | 54,561.29 | 53,745.55 | 52,964.83 | 52,169.19 | 51,382.61 | 50,628.24 | 49,858.06 | |
| 12 | | | | | | | | | | | | | |
| 13 Carrying Cost | | | | | | | | | | | | | |
| 14 Equity | 232.42 | 228.93 | 225.52 | 222.46 | 219.14 | 215.97 | 212.74 | 209.65 | 206.50 | 203.39 | 200.40 | 197.35 | |
| 15 Equity % of Cap Struct | 9.5000% | | | | | | | | | | | | |
| 16 Equity Pretax | 333.37 | 320.88 | 313.79 | 315.08 | 308.50 | 314.08 | 309.31 | 305.04 | 296.29 | 290.97 | 287.84 | 281.54 | |
| 17 Debt | 148.16 | 145.94 | 143.76 | 141.81 | 139.70 | 137.68 | 135.62 | 133.65 | 131.64 | 129.66 | 127.75 | 125.81 | |
| 18 Total Carrying Cost | 481.53 | 466.81 | 457.55 | 456.89 | 448.20 | 451.76 | 444.93 | 438.69 | 427.93 | 420.63 | 415.59 | 407.35 | 5,317.86 |
| 19 | | | | | | | | | | | | | 0.1238 |
| 20 Total Cost | 2,492.98 | 2,522.34 | 2,486.26 | 2,299.91 | 2,421.01 | 2,339.36 | 2,393.44 | 2,295.07 | 2,285.22 | 2,260.40 | 2,190.53 | 2,213.24 | 28,199.76 |
| 21 Total Volume | 3,825.39 | 3,894.16 | 3,823.78 | 3,404.67 | 3,711.77 | 3,537.53 | 3,606.62 | 3,444.54 | 3,513.57 | 3,471.68 | 3,322.55 | 3,395.78 | 42,952.03 |
| 22 Total Rate Per Therm | 0.652 | 0.648 | 0.650 | 0.676 | 0.652 | 0.661 | 0.664 | 0.666 | 0.650 | 0.651 | 0.659 | 0.652 | 0.657 |

| Non-Carry Wells Gas Reserves Deal | | | | | | | | | | | | | |
|--------------------------------------|-------------------------------|-------------------------------|------------------------------|-------------------------------|----------------------------|----------------------------|--------------------------|---------------------------|---------------------------|-----------------------------|--------------------------------|------------------------------|----------------------------|
| | Projected November 2017 | Projected December 2017 | Projected January 2018 | Projected February 2018 | Projected March 2018 | Projected April 2018 | Projected May 2018 | Projected June 2018 | Projected July 2018 | Projected August 2018 | Projected September 2018 | Projected October 2018 | Projected PGA Totals |
| Therms Delivered (000s) | | | | | | | | | | | | | |
| Total Therms | 183.31 | 186.04 | 182.80 | 162.30 | 176.69 | 168.20 | 171.04 | 162.93 | 165.79 | 163.30 | 155.71 | 158.58 | 2,036.69 |
| Rate per Therm (Depletion Rate) | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 | 0.4278 |
| Delivery Value | 78.43 | 79.60 | 78.21 | 69.44 | 75.60 | 71.96 | 73.18 | 69.71 | 70.93 | 69.87 | 66.62 | 67.85 | 871.37 |
| | | | | | | | | | | | | | 0.4278 |
| Opex / Severance / Ad Valorem | | | | | | | | | | | | | |
| Operating Cost | 19.77 | 19.94 | 19.81 | 18.93 | 19.70 | 19.65 | 20.65 | 19.72 | 18.96 | 18.86 | 18.54 | 18.65 | 233.19 |
| Severance and Ad Valorem Taxes | 6.38 | 7.11 | 7.16 | 6.28 | 6.30 | 4.95 | 4.80 | 4.63 | 4.95 | 4.90 | 4.63 | 4.70 | 66.80 |
| Total | 26.15 | 27.04 | 26.97 | 25.21 | 26.00 | 24.60 | 25.46 | 24.35 | 23.91 | 23.76 | 23.17 | 23.35 | 299.99 |
| Average Rate Base | 3,668.34 | 3,616.68 | 3,566.86 | 3,522.34 | 3,474.09 | 3,428.05 | 3,381.27 | 3,336.59 | 3,291.17 | 3,246.39 | 3,203.58 | 3,160.03 | 0.1473 |
| Carrying Cost | | | | | | | | | | | | | |
| Equity | 14.52 | 14.32 | 14.12 | 13.94 | 13.75 | 13.57 | 13.38 | 13.21 | 13.03 | 12.85 | 12.68 | 12.51 | |
| Equity % of Cap Struct | 9.5000% | | | | | | | | | | | | |
| Equity Pretax | 23.98 | 23.65 | 23.32 | 23.03 | 22.71 | 22.41 | 22.11 | 21.82 | 21.52 | 21.23 | 20.95 | 20.66 | |
| Debt | 9.26 | 9.13 | 9.00 | 8.89 | 8.77 | 8.65 | 8.53 | 8.42 | 8.30 | 8.19 | 8.08 | 7.97 | |
| Total Carrying Cost | 33.24 | 32.77 | 32.32 | 31.92 | 31.48 | 31.06 | 30.64 | 30.23 | 29.82 | 29.42 | 29.03 | 28.63 | 370.58 |
| Total Cost | 137.82 | 139.41 | 137.50 | 126.56 | 133.08 | 127.63 | 129.27 | 124.30 | 124.67 | 123.04 | 118.82 | 119.83 | 0.1820 |
| Total Volume | 183.31 | 186.04 | 182.80 | 162.30 | 176.69 | 168.20 | 171.04 | 162.93 | 165.79 | 163.30 | 155.71 | 158.58 | 1,541.94 |
| Total Rate Per Therm [1] | 0.752 | 0.749 | 0.752 | 0.780 | 0.753 | 0.759 | 0.756 | 0.763 | 0.752 | 0.753 | 0.763 | 0.756 | 2,036.69 |
| | | | | | | | | | | | | | 0.757 |

[1] The actual price included within WACOG is \$4.725/Dth per Order No. 15-297

NW Natural
Rates & Regulatory Affairs
2017-18 PGA - Oregon: August Filing
Attachment C: 3% Test

| | Surcharge | Credit |
|---|------------------|---------------|
| 1 2017-2018 PGA Gas Cost True- | | |
| 2 Up | | (15,624,355) |
| 3 | | |
| 4 Non-Gas Cost Amortizations | | |
| 5 WARM | (4,959,640) | |
| 6 Residual Deferral | (55,770) | |
| 7 Intervenor Funding | 89,497 | |
| 8 Oregon Regulatory Fee | 290,836 | |
| 9 Industrial DSM | 3,880,011 | |
| 9 Decoupling | 12,379,031 | |
| 10 Subtotal | 11,623,965 | (15,624,355) |
| 11 | | |
| 12 Total | (4,000,390) | |
| 13 | | |
| 14 Total Proposed Amortization | | (4,000,390) |
| 15 Less: | | |
| 16 Intervenor Funding ¹ | | (89,497) |
| 17 Industrial DSM ¹ | | (3,880,011) |
| 18 Decoupling ¹ | | (12,379,031) |
| 19 | | |
| 20 Net Proposed Amortizations (subject to the 3% test) | | (20,348,929) |
| 21 | | |
| 22 Utility Gross Revenues (2016) ² | | 607,209,577 |
| 23 | | |
| 24 3% of Utility Gross Revenues | | 18,216,287 |
| 25 | | |
| 26 Allowed Amortization | | (20,348,929) |
| 27 | | |
| 28 Allowed Amortization as % of Gross Revenues | | -3.4% |

Notes:

¹ Amortizations of the deferral are not subject to the 3% test pursuant to ORS 757.259 as they are automatic adjustment clauses.

² Unadjusted general revenues as shown in the most recent ROO.

NW Natural
Rates & Regulatory Affairs
2017-18 PGA - Oregon: August Filing
Effects on Average Bill by Rate Schedule [1]

Advice 17-12

ALL VOLUMES IN THERMS

See note [9]

| 1 | Oregon PGA | | Normal | Minimum | 11/1/2016 | 11/1/2016 | Proposed | Proposed | Proposed | | |
|----|------------------|-----------|-------------|----------------|-----------|--------------|-----------------|--------------|-----------------|-----------------|-------|
| 2 | Normalized | | Therms | Monthly | Billing | Current | 11/1/2017 | 11/1/2017 | 11/1/2017 | | |
| 3 | Volumes page, | | Monthly | Charge | Rates | Average Bill | PGA | PGA | PGA | | |
| 4 | Column D | | Average use | | | | Rates | Average Bill | % Bill Change | | |
| 5 | | Therms in | | | | | | | | | |
| 6 | Schedule | Block | Block | C | D | E | F = D + (C * E) | V | W = D + (C * V) | X = (W - F) / F | |
| 7 | | | A | B | | | F | | W | X | |
| 7 | 2R | | 353,902,060 | N/A | 50 | \$8.00 | \$0.90723 | \$53.36 | \$0.86223 | \$51.11 | -4.2% |
| 8 | 3C Firm Sales | | 159,700,612 | N/A | 231 | \$15.00 | \$0.86447 | \$214.69 | \$0.81947 | \$204.30 | -4.8% |
| 9 | 3I Firm Sales | | 4,602,931 | N/A | 1,118 | \$15.00 | \$0.82099 | \$932.87 | \$0.77599 | \$882.56 | -5.4% |
| 10 | 27 Dry Out | | 1,205,372 | N/A | 51 | \$6.00 | \$0.79183 | \$46.38 | \$0.74683 | \$44.09 | -4.9% |
| 11 | 31C Firm Sales | Block 1 | 13,316,134 | 2,000 | 2,878 | \$325.00 | \$0.59951 | \$2,033.45 | \$0.55662 | \$1,910.02 | -6.1% |
| 12 | | Block 2 | 12,481,400 | all additional | | | \$0.58022 | | \$0.53733 | | |
| 13 | 31C Firm Trans | Block 1 | 1,525,441 | 2,000 | 1,718 | \$575.00 | \$0.19261 | \$905.90 | \$0.19261 | \$905.90 | 0.0% |
| 14 | | Block 2 | 2,009,166 | all additional | | | \$0.17612 | | \$0.17612 | | |
| 15 | 31I Firm Sales | Block 1 | 4,070,024 | 2,000 | 5,101 | \$325.00 | \$0.52142 | \$2,932.08 | \$0.47853 | \$2,713.30 | -7.5% |
| 16 | | Block 2 | 8,722,092 | all additional | | | \$0.50443 | | \$0.46154 | | |
| 17 | 31I Firm Trans | Block 1 | 125,106 | 2,000 | 5,582 | \$575.00 | \$0.17295 | \$1,480.91 | \$0.17295 | \$1,480.91 | 0.0% |
| 18 | | Block 2 | 276,784 | all additional | | | \$0.15634 | | \$0.15634 | | |
| 19 | 32C Firm Sales | Block 1 | 25,883,715 | 10,000 | 6,918 | \$675.00 | \$0.45060 | \$3,792.25 | \$0.40771 | \$3,495.54 | -7.8% |
| 20 | | Block 2 | 8,661,618 | 20,000 | | | \$0.43472 | | \$0.39183 | | |
| 21 | | Block 3 | 1,237,042 | 20,000 | | | \$0.40833 | | \$0.36544 | | |
| 22 | | Block 4 | 165,932 | 100,000 | | | \$0.38189 | | \$0.33900 | | |
| 23 | | Block 5 | 0 | 600,000 | | | \$0.36585 | | \$0.32296 | | |
| 24 | | Block 6 | 0 | all additional | | | \$0.35526 | | \$0.31237 | | |
| 25 | 32I Firm Sales | Block 1 | 4,719,808 | 10,000 | 18,967 | \$675.00 | \$0.44761 | \$9,026.91 | \$0.40472 | \$8,213.41 | -9.0% |
| 26 | | Block 2 | 5,298,281 | 20,000 | | | \$0.43223 | | \$0.38934 | | |
| 27 | | Block 3 | 1,764,186 | 20,000 | | | \$0.40657 | | \$0.36368 | | |
| 28 | | Block 4 | 508,368 | 100,000 | | | \$0.38095 | | \$0.33806 | | |
| 29 | | Block 5 | 0 | 600,000 | | | \$0.36535 | | \$0.32246 | | |
| 30 | | Block 6 | 0 | all additional | | | \$0.35515 | | \$0.31226 | | |
| 31 | 32 Firm Trans | Block 1 | 16,254,618 | 10,000 | 42,165 | \$925.00 | \$0.10157 | \$4,409.93 | \$0.10157 | \$4,409.93 | 0.0% |
| 32 | | Block 2 | 18,153,953 | 20,000 | | | \$0.08634 | | \$0.08634 | | |
| 33 | | Block 3 | 10,538,827 | 20,000 | | | \$0.06103 | | \$0.06103 | | |
| 34 | | Block 4 | 19,469,774 | 100,000 | | | \$0.03567 | | \$0.03567 | | |
| 35 | | Block 5 | 21,237,750 | 600,000 | | | \$0.02045 | | \$0.02045 | | |
| 36 | | Block 6 | 3,397,316 | all additional | | | \$0.01035 | | \$0.01035 | | |
| 37 | 32C Interr Sales | Block 1 | 5,242,630 | 10,000 | 31,274 | \$675.00 | \$0.43726 | \$13,982.77 | \$0.42115 | \$13,478.94 | -3.6% |
| 38 | | Block 2 | 7,424,480 | 20,000 | | | \$0.42157 | | \$0.40546 | | |
| 39 | | Block 3 | 3,966,495 | 20,000 | | | \$0.39542 | | \$0.37931 | | |
| 40 | | Block 4 | 4,896,519 | 100,000 | | | \$0.36927 | | \$0.35316 | | |
| 41 | | Block 5 | 236,893 | 600,000 | | | \$0.35356 | | \$0.33745 | | |
| 42 | | Block 6 | 0 | all additional | | | \$0.34299 | | \$0.32688 | | |
| 43 | 32I Interr Sales | Block 1 | 6,200,783 | 10,000 | 34,814 | \$675.00 | \$0.43711 | \$15,379.11 | \$0.42100 | \$14,818.25 | -3.6% |
| 44 | | Block 2 | 7,447,078 | 20,000 | | | \$0.42148 | | \$0.40537 | | |
| 45 | | Block 3 | 3,991,226 | 20,000 | | | \$0.39539 | | \$0.37928 | | |
| 46 | | Block 4 | 8,413,466 | 100,000 | | | \$0.36930 | | \$0.35319 | | |
| 47 | | Block 5 | 1,938,065 | 600,000 | | | \$0.35364 | | \$0.33753 | | |
| 48 | | Block 6 | 0 | all additional | | | \$0.34310 | | \$0.32699 | | |
| 49 | 32 Interr Trans | Block 1 | 8,753,845 | 10,000 | 208,347 | \$925.00 | \$0.10200 | \$9,686.23 | \$0.10200 | \$9,686.23 | 0.0% |
| 50 | | Block 2 | 15,798,206 | 20,000 | | | \$0.08673 | | \$0.08673 | | |
| 51 | | Block 3 | 11,612,336 | 20,000 | | | \$0.06128 | | \$0.06128 | | |
| 52 | | Block 4 | 31,071,223 | 100,000 | | | \$0.03582 | | \$0.03582 | | |
| 53 | | Block 5 | 59,059,181 | 600,000 | | | \$0.02055 | | \$0.02055 | | |
| 54 | | Block 6 | 91,219,916 | all additional | | | \$0.01038 | | \$0.01038 | | |
| 55 | 33 | | 0 | N/A | 0 | \$38,000 | \$0.00590 | \$38,000.00 | \$0.00590 | \$38,000.00 | 0.0% |
| 56 | | | | | | | | | | | |
| 57 | Totals | | 966,500,651 | | | | | | | | |

[1] For convenience of presentation, the cent per therm demand charge is used, rather than the available MDDV demand
 [2] Tariff Advice Notice 17-05: Non-Gas Cost Deferral Amortizations - Intervenor Funding
 [3] Tariff Advice Notice 17-06: Non-Gas Cost Deferral Amortizations - Residual Account
 [4] Tariff Advice Notice 17-07: Non-Gas Cost Deferral Amortizations - Oregon PUC Fee
 [5] Tariff Advice Notice 17-08: Non-Gas Cost Deferral Amortizations - SRRM
 [6] Tariff Advice Notice 17-09: Non-Gas Cost Deferral Amortizations - Industrial DSM
 [7] Tariff Advice Notice 17-10: Non-Gas Cost Deferral Amortizations - Decoupling
 [8] Tariff Advice Notice 17-11: Non-Gas Cost Deferral Amortizations - WARM
 [9] Tariff Advice Notice 17-12: PGA

NW Natural
Rates and Regulatory Affairs
2017-2018 PGA Filing - OREGON
Basis for Revenue Related Costs

| | Twelve Months <u>Ended 06/30/17</u> | | |
|----|--|----------------|------------------------------------|
| 1 | | | |
| 2 | | | |
| 3 | Total Billed Gas Sales Revenues | \$ 674,696,212 | |
| 4 | Total Oregon Revenues | \$ 678,088,466 | |
| 5 | | | |
| 6 | Regulatory Commission Fees [1] | n/a | 0.300% Statutory rate |
| 7 | City License and Franchise Fees | \$ 16,069,889 | 2.370% Line 7 ÷ Line 4 |
| 8 | Net Uncollectible Expense [2] | \$ 848,945 | 0.125% Line 8 ÷ Line 4 |
| 9 | | | |
| 10 | Total | | <u><u>2.795%</u></u> Sum lines 8-9 |
| 11 | | | |
| 12 | | | |

13 **Note:**

14 [1] Dollar figure is set at statutory level of 0.275% times Total Oregon Revenues (line 4).

15 Because the fee changed occurred mid gas year, the difference between the previous fee of 0.275%
 16 and the new fee of 0.3% is being captured as a temporary deferral.

17 [2] Represents the normalized net write-offs based on a three-year average.

NW Natural
Rates & Regulatory Affairs
2017-2018 PGA Filing - Oregon: August Filing
PGA Effects on Revenue
Tariff Advice 17-12: PGA Gas Costs and Gas Cost Deferrals

| | Including Revenue <u>Sensitive Amount</u> |
|----|--|
| 1 | |
| 2 | |
| 3 | |
| 4 | |
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| 24 | |
| 25 | |
| 26 | |
| 27 | |

Purchased Gas Cost Adjustment (PGA)

Commodity Cost Change (\$11,344,389)

Demand Capacity Cost Change (1,370,387)

Total Gas Cost Change (12,714,776)

Temporary Increments

Removal of Current Temporary Increments
 Amortization of 191.xxx Account Gas Costs 408,763

Addition of Proposed Temporary Increments
 Amortization of 191.xxx Account Gas Costs (15,624,355)

Net Temporary Rate Adjustment (15,215,592)

TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES (\$27,930,368)

2016 Oregon Earnings Test Normalized Total Revenues \$645,156,000

Effect of this filing, as a percentage change (line 21 ÷ line 25) -4.33%

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

NW NATURAL SUPPORTING MATERIALS

Purchased Gas Cost

NWN OPUC Advice No. 17-12 / UG 334

July 28, 2017

| GUIDELINE REFERENCE | DATA REQUIREMENT | Page No. | STATUS |
|---------------------|---|----------|----------------------------|
| IV | General Information and Forecasting | | |
| 1 | General Information | | |
| a) | Definitions of all major terms and acronyms in the data and information provided. | 4 | |
| b) | Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment. | 6 | |
| c) | All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers. | 7 | |
| 2 | Workpapers | | |
| a) | PGA Summary Sheet | 8 | |
| b) | Gas Supply Portfolio and Related Transportation | | |
| 1 | Summary of portfolio planning | 10 | |
| 2 | LDC sales system demand forecasting | 11 | |
| 3 | Natural gas price forecasts | 11 | |
| 4 | Physical resources for the portfolio | 12 | |
| | Supporting Tables | 17-20 | |
| 5 | Financial resources for the portfolio (derivatives and other financial arrangements). | 14 | CONFIDENTIAL |
| 6 | Storage resources. | 15 | |
| 7 | Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation. | 21 | |
| 8 | Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation. | 21 | |
| 9 | Summary of portfolio documentation provided | 21 | |
| V.1 | Physical Gas Supply | | HIGHLY CONFIDENTIAL |
| a) | For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following: | 22 | |
| 1 | Pricing for the resource, including the commodity price and, if relevant, reservation charges. | 22 | |
| 2 | For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices, utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process. | 22 | |
| 3 | Brief explanation of each contract's role within the portfolio. | 22 | |

| GUIDELINE REFERENCE | DATA REQUIREMENT | Page No. | STATUS |
|---------------------|---|----------|----------------------------|
| b) | For purchases of physical natural gas supply resource from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following: | 24 | |
| 1 | An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are completed by the utility. | 24 | |
| 2 | Any contract provisions that materially deviate from the standard NAESB contract. | 25 | |
| | | | |
| V.2 | Hedging | | |
| | The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio. | 26 | HIGHLY CONFIDENTIAL |
| | | | |
| V.3 | Load Forecasting | | |
| a) | Customer count and revenue by month and class. | 28 | |
| b) | Historical (five years) and forecasted (one year ahead) sales system physical peak demand. | 29 | |
| c) | Historical (five years), and forecasted (one year ahead) sales system physical annual demand. | 29 | |
| d) | Historical (five years), and forecasted (one year ahead) sales system physical demand for each of following, | 29 | |
| 1 | Annual for each customer class | 29 | |
| 2 | Annual and monthly baseload. | 30 | |
| 3 | Annual and monthly non-baseload. | 30 | |
| 4 | Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update. | 31 | |
| | | | |
| V.4 | Market Information | | |
| | General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points. | 32 | |
| | | | |
| V.5 | Data Interpretation | | |
| | If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio. | 36 | |
| V.6 | Credit Worthiness Standards | | |

| GUIDELINE REFERENCE | DATA REQUIREMENT | Page No. | STATUS |
|---------------------|---|----------|---------------------|
| | A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so. | 37 | |
| | NW Natural Gas Supply Risk Management Policies | 38 | CONFIDENTIAL |
| V.7 | Storage | | |
| | Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based. | 65 | |
| a) | Type of storage (e.g., depleted field, salt dome). | 65 | |
| b) | Location of each storage facility. | 65 | |
| c) | Total level of storage in terms of deliverability and capacity held during the gas year. | 65 | |
| d) | Historical (five years) gas supply delivered to storage, both annual total and by month. | 65 | |
| e) | Historical (five years) gas supply withdrawn from storage, both annual total and by month. | 65 | |
| f) | An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas. | 67 | |
| g) | Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio. | 67 | CONFIDENTIAL |
| h) | For LDCs that own and operate storage: | | CONFIDENTIAL |
| a. | The date and results of the last engineering study for that storage. | 86 | |
| b. | A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed. | 101 | |
| V.8 | Attestation as to Consistency | 102 | |

Section IV. General Information and Forecasting

1. General Information

a) Definitions of all major terms and acronyms in the data and information provided.

| | |
|--|--|
| AECO | The industry acronym used for Alberta sourced natural gas supply. It originally comes from Alberta Energy Company which was incorporated in 1973 by the Alberta government (fully divested in 1993). |
| <i>Base Load gas (contract)</i> | Purchase agreements in which NW Natural has to take a set amount of gas each day from a supplier for the term of the agreement. Usually involves paying for any gas not taken unless excused by reason of Force Majeure. |
| <i>Base Rate</i> | The portion of rates that does not change outside of a general rate case, except as allowed through a Commission approved base rate adjustment. |
| <i>Base Rate Adjustment</i> | A permanent adjustment to rates approved by the Commission outside of a general rate case process. |
| Btu | British thermal unit. 100,000 Btus is equivalent to one therm. |
| CGPR | Canadian Gas Price Reporter. This is the industry publication in Canada that is put out by Canadian Enerdata Ltd and is the exclusive source of Canadian natural gas storage and price forecasts and publishes first of month Canadian indices used in baseload purchase pricing |
| <i>Collar</i> | Financial hedges that set ceiling and floor values on the price of gas purchases. |
| <i>Commodity Component</i> | The Tariff term used to refer to the cost of gas component of a customer's billing rate, and which will equal either (a) the Annual Sales WACOG, (b) the Winter Sales WACOG, or (c) the Monthly Incremental Cost of Gas. |
| Dth | Dekatherm. A unit of measure equal to 10 therms or one million Btu. |
| <i>Demand [Charge]</i> | The term used to refer to Pipeline Capacity related costs. |
| <i>Derivative products</i> | Financial transactions related to gas supply, including but not limited to hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers. |
| EIA | U.S. Energy Information Administration |
| FERC | Federal Energy Regulatory Commission |
| <i>Financial swaps</i> | Transactions that involve an exchange of cash flows with a counterparty. |

| | |
|---------------------------------------|---|
| <i>Financially hedged</i> | Purchases that have associated financial swaps such that the price of the gas is fixed for a pre-determined period of time. |
| FOM | First of Month |
| Fuel-in-Kind (KIG) | The published fuel rate calculated based on the amount of fuel used on each pipeline to run the compressors and other equipment to move gas across their pipes. Fuel is taken in kind from all receipt shippers by reducing each shippers daily volumes in accordance to the pipelines estimated fuel requirements. |
| GMR-NWP Rockies | Inside FERC's Gas Market Report, a publication put out by Platts (a McGraw-Hill subsidiary) that is the source used for price forecasts and indices that used to set US baseload and some daily purchase prices. |
| IRP | Integrated Resource Plan |
| MDDV | Maximum Daily Delivery Volume |
| NWP | Northwest Pipeline |
| Off-system storage | Storage facilities located outside NW Natural's service territory. |
| On-system storage | Storage facilities located inside NW Natural's service territory. |
| PGA | Purchased Gas Adjustment |
| Peak day | The day in which volumes distributed or sold by NW Natural are at a maximum. May be theoretical (the "design day") or actual. |
| Pipeline Capacity | The quantity (volume) of natural gas available on the interstate pipeline for the transportation of gas supplies to the Company's distribution system. Pipeline Capacity related costs are often referred to as "Demand". |
| Recallable gas supply/capacity | Refers to arrangements that allow NW Natural to use the upstream pipeline capacity and gas supplies held by third parties. |
| Revenue Sensitive | The amount by which rates are adjusted to reflect the effects of revenue related costs, such as uncollectible expense, regulatory fees, and city license and franchise fees |
| Swing gas (contract) | Purchase agreements in which NW Natural has the right, but not the obligation, to take gas from a supplier on any given day. |
| Technical Rate Adjustments | Also referred to as Temporary Rate Adjustments. |
| Therm | A unit of heating value equivalent to 100,000 Btus. The amount of heat energy in approximately 100 cubic feet of Natural Gas. |
| Total Commodity Cost | The combined costs for all purchased gas supplies, excluding transportation costs. |

| | |
|--|--|
| <i>Total Gas Cost</i> | The combined costs of all purchased gas supplies and associated transportation costs. |
| <i>Transportation Cost</i> | The combined costs for all pipeline related demand, capacity or reservation charges |
| <i>Transportation Resources</i> | The various upstream pipeline capacity agreements held by the company. |
| <i>Upstream pipeline</i> | Those pipelines that collect natural gas from the areas where it is produced in the British Columbia, Alberta and the U.S. Rocky Mountain supply regions and transport that gas to NW Natural's service territory. |
| <i>Upstream pipeline capacity</i> | Refers to the rights that NW Natural has obtained to transport gas on upstream pipelines. |
| <i>WACOG</i> | The Company's weighted average commodity cost of gas (excluding transportation cost), also referred to as Annual Sales WACOG. |
| <i>Winter Sales WACOG</i> | The Company's winter period weighted average commodity cost of gas (excluding transportation cost). |

b) Any significant new regulatory requirements identified by the utility that in the utility's judgment directly impacts the Oregon portfolio design, implementation, or assessment.

The administration of President Trump has created many uncertainties in the natural gas industry, including the potential roll-back of certain regulations, renegotiation of NAFTA, encouragement of LNG exports, and the tax treatment of foreign goods. That last item could encompass the two-thirds of our gas supplies that are purchased in western Canada and imported into the United States, the steel pipeline used by the industry, and so on. However, the only uncertainty that is currently of tangible concern in this filing is the timing to confirm at least two new FERC commissioners. FERC has lacked a quorum for several months, and so an uncontested settlement between Northwest Pipeline and its shippers to lower rates effective January 1, 2018, still awaits FERC approval. The expectation is that new commissioners will be in place well before the end of this year, and so the negotiated rate reduction of about 7%, and a future reduction of less than 1% effective October 1, 2018, are reflected in our PGA filing.

The WUTC issued a Policy Statement on Natural Gas Hedging Practices in March 2017. It created no impact on the formulation of the current PGA filing, and its effect on future PGA filings is still being assessed.

- c) All forecasts of demand, weather, etc. upon which the gas supply portfolio for the current PGA filing is based should be based on a methodology and data sources that are consistent with the most recently acknowledged IRP or IRP update for the utility. If the methodology and/or data sources are not consistent each difference should be identified, explained, and documented as part of the PGA filing workpapers.**

And

Attestation of verification of consistency

In accordance with the PGA Portfolio Guidelines at Section IV(1)(c), the Company acknowledges that all forecasts of demand, weather, etc., upon which the gas supply portfolio for this PGA filing is based, uses the methodology and data sources that are consistent with the Company's recently acknowledged 2016 IRP.

2. Workpapers

a) PGA Summary

| | Amount | Location in Company Filing (cite) |
|---|----------------|--|
| 1) Change in Annual Revenues | | |
| (Per OAR 860-022-0017(3)(a)) | | |
| A) Dollars (To .1 million) | (\$37,400,000) | Refer to workpaper "PGA filing Summary Effects" |
| B) Percent (To .1 percent) | -5.79% | " |
| 2) Annual Revenues Calculation (Whole Dollars) | | |
| A) PGA Cost Change (Commodity & Transportation) | (\$12,714,766) | Refer to workpaper "PGA filing Summary Effects" |
| B) Remove Last Year's Temporary Increment Total | (\$27,046,184) | " |
| C) Add New Temporary Increment | \$2,400,975 | " |
| D) Other Additions or Subtractions (Break out & List each below -- Attach additional sheet if necessary) | | |
| 1) | | Refer to workpaper "PGA filing Summary Effects" |
| 2) | | " |
| 3) | | |
| 4) | | |
| 5) | | |
| 6) | | |
| E) Total Proposed Change | (\$37,359,985) | " |
| 3) Residential Bill Effects Summary | | |
| A) Residential Schedule 2 Rate Impacts | | |
| 1) Current Billing Rate per Therm | \$0.90723 | Refer to workpaper "2016-17 Rate Development" |
| 2) Proposed Billing Rate per Therm | \$0.84428 | " |
| 3) Rate Change Per Therm | (\$0.06295) | " |
| 4) Percent Change per Therm (to .1%) | -6.9% | " |
| B) Average Residential Bill Impact (forecasted weather-normalized annual) | | |
| 1) Average Residential Monthly Use | 50.0 | Refer to workpaper "2016-17 Rate Development" |
| 2) Customer Charge | \$8.00 | " |
| 3) Current Average Monthly Bill | \$53.36 | " |
| 4) Proposed Average Monthly Bill | \$50.21 | "2017-18 Rate Development" |
| 5) Change in Average Monthly Bill | (\$3.15) | " |
| 6) Percent change in Average Monthly Bill (to .1%) | -5.9% | " |
| C) Average January Residential Bill Impact | | |
| 1) Average January Residential Use (forecasted weather-normalized) | 150.0 | N/A |
| 2) Customer Charge | \$8.00 | N/A |
| 3) Current Average January Bill | \$144.30 | "2016-17 Rate Development" |
| 4) Proposed Average January Bill | \$134.84 | "2017-18 Rate Development" |
| 5) Change in Average January Bill | (\$9.46) | N/A |
| 6) Percent change in Average January Bill (to .1%) | -6.6% | N/A |

| | Amount | Location in Company Filing (cite) |
|--|---------------|-----------------------------------|
| 4) Breakdown of Costs | | |
| A) Embedded in Rates | | |
| 1) Total Commodity Cost | \$223,199,160 | 2016-17 PGA filing |
| a) Total Demand Cost (assoc. w/ supply) | | |
| b) Total Peaking Cost (assoc. w/ supply) | | |
| c) Total Reservation Cost (assoc. w/ supply) | | |
| d) Total Volumetric Cost (assoc. w/ supply) | \$2,015,456 | 2016-17 PGA filing |
| e) Total Storage Cost (assoc. w/ supply) | \$48,040,220 | 2016-17 PGA filing |
| f) Other | \$31,263,614 | 2016-17 PGA filing |
| 2) Total Transportation Cost (<i>Pipeline related</i>) | \$80,512,202 | 2016-17 PGA filing |
| a) Total Upstream Canadian Toll | \$0 | |
| i. Total Demand, Capacity, or Reservation Cost | \$0 | |
| ii. Total Volumetric Cost | \$0 | |
| b) Total Domestic Cost | \$0 | |
| i. Total Demand, Capacity, or Reservation Cost | \$0 | |
| ii. Total Volumetric Cost | \$0 | |
| 3) Total Storage Costs | \$0 | |
| 4) Capacity Release Credits | \$0 | |
| 5) Total Gas Costs | \$303,711,362 | |
| B) Projected For New Rates | | |
| 1) Total Commodity Cost | \$208,930,758 | Exhibit B, Page 1 |
| a) Total Demand Cost (assoc. w/ supply) | | |
| b) Total Peaking Cost (assoc. w/ supply) | | |
| c) Total Reservation Cost (assoc. w/ supply) | | |
| d) Total Vaporization Cost (assoc. w/ supply) | | |
| e) Total Volumetric Cost (assoc. w/ supply) | \$1,051,007 | Exhibit B, Page 1 |
| f) Total Storage Cost (assoc. w/ supply) | \$41,197,181 | Exhibit B, Page 1 |
| g) Other (A&G Benchmark Savings) | \$29,287,442 | Exhibit B, Page 1 |
| 2) Total Transportation Cost (<i>Pipeline related</i>) | \$79,266,586 | Exhibit B, Page 3 |
| a) Total Upstream Canadian Toll | \$0 | |
| i. Total Demand, Capacity, or Reservation Cost | \$0 | |
| ii. Total Volumetric Cost | \$0 | |
| b) Total Domestic Cost | \$0 | |
| i. Total Demand, Capacity, or Reservation Cost | \$0 | |
| ii. Total Volumetric Cost | \$0 | |
| 3) Total Storage Costs | \$0 | |
| 4) Capacity Release Credits | \$0 | |
| 5) Total Gas Costs | \$288,197,344 | |
| 5) WACOG (<i>Weighted Average Cost of Gas</i>) | | |
| A) Embedded in Rates | | |
| 1) WACOG (<i>Commodity Only</i>) | | |
| a. With revenue sensitive | \$0.31517 | N/A |
| b. Without revenue sensitive | \$0.30613 | N/A |
| 2) WACOG (<i>Non-Commodity</i>) | | |
| a. With revenue sensitive | \$0.12132 | N/A |
| b. Without revenue sensitive | \$0.11784 | N/A |

| | Amount | Location in Company Filing (cite) |
|---|-------------|-----------------------------------|
| B) Proposed for New Rates | | |
| 1) WACOG (Commodity Only) | | |
| a. With revenue sensitive | \$0.29764 | Exhibit B, Page 6 and Page 9 |
| b. Without revenue sensitive | \$0.28932 | " |
| 2) WACOG (Non-Commodity) | | |
| a. With revenue sensitive | \$0.11921 | Exhibit B, Page 8 |
| b. Without revenue sensitive | \$0.11588 | " |
| 6) Therms Sold | 655,997,209 | Exhibit B, Page 1 |
| 7) Purchasing/ Hedging Strategies <i>Prepare 1-2 page summary of gas cost situation to include resources, purchasing strategy, hedging, and pipeline issues. Within the summary include:</i> | | |
| A) Resources embedded in current rates and an explanation of proposed resources. | | |
| 1) Firm Pipeline Capacity | | |
| a. Year-round supply contracts | N/A | Exhibit A, IV.2.b 1-7 |
| b. Winter-only contracts | N/A | " |
| c. Reliance on Spot Gas/Other Short Term Contracts | N/A | " |
| d. Other - e.g. Supply area storage | N/A | " |
| 2) Market Area Storage | | |
| a. Underground-owned | N/A | " |
| b. Underground- contracted | N/A | " |
| c. LNG-owned | N/A | " |
| d. LNG-contracted | N/A | " |
| 3) Other Resources | | |
| a. Recallable Supply | N/A | " |
| b. City gate Deliveries | N/A | " |
| c. Owned-Production | N/A | " |
| d. Propane/Air | N/A | " |

b) Gas Supply Portfolio and Related Transportation

1. Summary of portfolio planning

The gas supply planning process focuses on securing and dispatching gas supply resources to ensure reliable service to the Company's sales customers at a reasonable cost.

To ensure adequate reliability, NW Natural contracts for firm upstream pipeline capacity, firm off-system storage service and firm recallable gas supply/capacity arrangements with certain on-system customers, in addition to its development and use of on-system underground and LNG storage.

Upstream pipeline capacity has been contracted with the following objectives in mind: (1) Diversify capacity sources so that disruptions in any one supply region, such as from a pipeline rupture, well freeze-offs, etc., have a minimal impact on NW Natural; (2) Obtain upstream capacity along the path from NW Natural's service territory to points generally recognized for their liquidity, such as AECO/NIT, to maximize buying opportunities and minimize price volatility; and (3) Find ways to minimize the cost of upstream capacity such as through optimization activities or committing to capacity only on a winter season basis if possible.

Upstream gas supply contracts have been negotiated with the following objectives in mind:

- (1) Use a diverse group of reliable suppliers as established by their asset positions, past performance and other factors;
- (2) Try to match our year-round customer requirements to baseload (take-or-pay) annual or multi-year supply contracts to obtain the most favorable pricing;
- (3) Use winter only (Nov-Mar) term contracts to match our rise in requirements during the heating season;
- (4) Reduce spot purchase requirements during the winter due to the likely correlation of high requirements with high spot prices;
- (5) Take advantage of favorable pricing opportunities to use supply-basin storage when possible;
- (6) Use index-related pricing formulas in term contracts to enable easy evaluation of competitive offers and avoid the need for further price negotiation over the term of the contract;
- (7) Structure the portfolio to provide some opportunity to take advantage when spot prices are favorable; and
- (8) Avoid over-contracting gas on a take-or-pay basis, which could result in excess gas supplies that must be sold at a loss if requirements fail to materialize such as during a warm winter.

One item that would have been found in the above list in prior years was an objective to use a variety of term contract durations to avoid having to re-contract all physical gas supplies every year. More recently, with the surge in supplies represented by shale gas, the Company has decreased its reliance on multi-year physical term contracts, and as they have expired, replaced them with 1-year or shorter term purchases.

2. LDC sales system demand forecasting

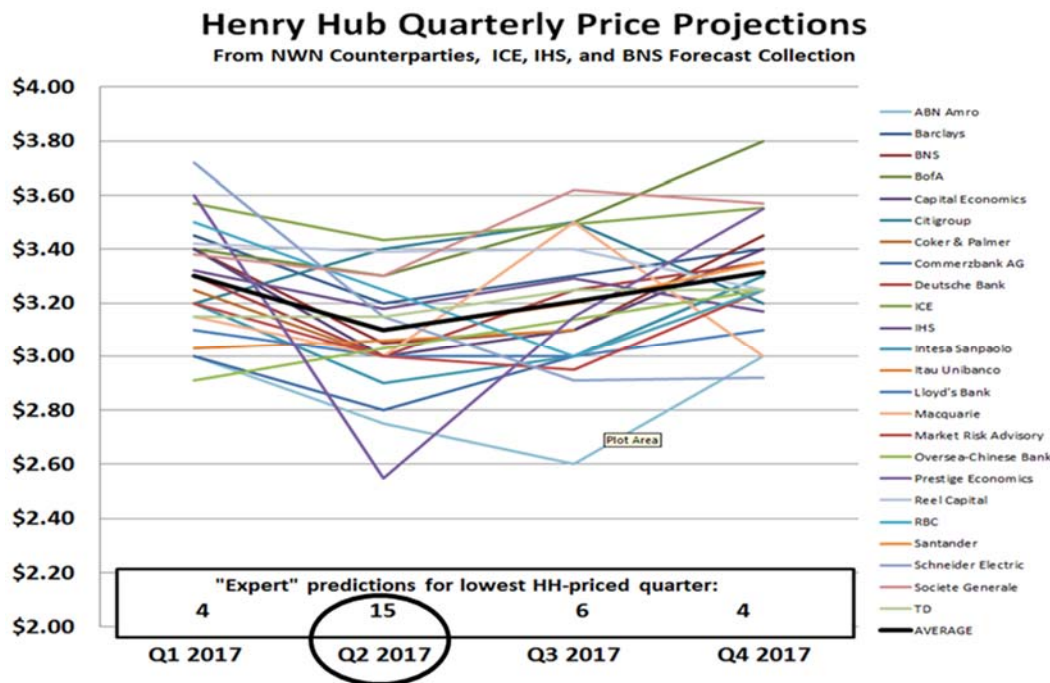
The Company's methodology for forecasting annual sales and firm peak day requirements is described in its Integrated Resource Plan (IRP), of which the latest is the 2016 IRP filed in August 2016 and subsequently acknowledged by the OPUC and the WUTC. Also applicable here is the load forecast methodology previously established for the PGA process.

This means that while the demand forecast reflects "normal" weather, the Company still is planning for the possibility of extreme cold weather during the upcoming heating season. Where these two differing load forecasts collide is in the dispatch of storage resources. To handle this conflict in load forecasting criteria, implicit in the resource dispatch are constraints that limit storage withdrawals to the extent needed to maintain maximum daily deliverabilities into early February. This addresses the need to maintain reliability of service to firm customers should extreme cold weather arise during the coming winter, while at the same time complying with the PGA load forecast requirements.

3. Natural gas price forecasts

NW Natural relies on forecasts prepared by the U.S. Energy Information Administration (EIA), the IHS consulting firm (formerly known as CERA and now moving to the name IHS Markit) as well as NYMEX futures prices to help formulate its gas purchase and hedging strategies. Various other price forecasts and analyses also come to NW Natural by way of trade publications, consultant visits, oil/gas company presentations and other governmental sources. These provide opportunities to test assumptions and explore alternate viewpoints.

As an example, the chart below contains 24 forecasts that NW Natural collected in late 2016 for Henry Hub prices during 2017. From this collection, a view emerges that prices could be lowest in the 2nd quarter of 2017. An analysis performed by NW Natural suggests that current prices are strongly correlated to the futures market, that is, a dip in current prices will drop future prices for the upcoming PGA year, and vice versa. Therefore, a low current price period is more opportune to perform gas price hedging for the PGA year than a high priced period.



4. Physical resources for the portfolio

As mentioned above, NW Natural's physical portfolio on any given day includes gas supplies purchased and transported over the upstream pipeline grid as well as supplies either placed into or withdrawn from a variety of gas storage facilities. The Company also has arrangements with three large on-system customers that allow it to call on their gas supplies on short notice for use by the company ("recall arrangements"). Finally, a very small portion of the company's gas supply (about 1%) is native gas produced from the Mist Field. This is the Company's only gas supply that does not require transportation at one time or another over some portion of the interstate pipeline system.

Five significant changes to the physical supply resource portfolio were discussed in last year's PGA filing. As a reminder, these were:

- (1) the continuing and expanded usage of segmented capacity as a resource, increasing from 438,000 to 607,000 therms/day;
- (2) adjustments to the on-system storage plant capabilities to reflect recent increases in the heat content of gas delivered over the interstate pipeline system due to a glut of natural gas liquids (NGLs) in the market that has reduced the processing of NGLs out of the natural gas stream;
- (3) the commencement of 120,000 therms/day of new Northwest Pipeline capacity (the "March Point" contract) that became effective on January 1, 2017;
- (4) the elimination of the need to continue a call option agreement for citygate deliveries due to the three resource increases mentioned above; and,
- (5) the negotiation of a two-year T-South service agreement for 190,000 therms/day, which did not increase gas delivered to NW Natural's system but was done for economic reasons as well as to ease the Company's total reliance on purchases of British Columbia sourced gas at Huntingdon/Sumas.

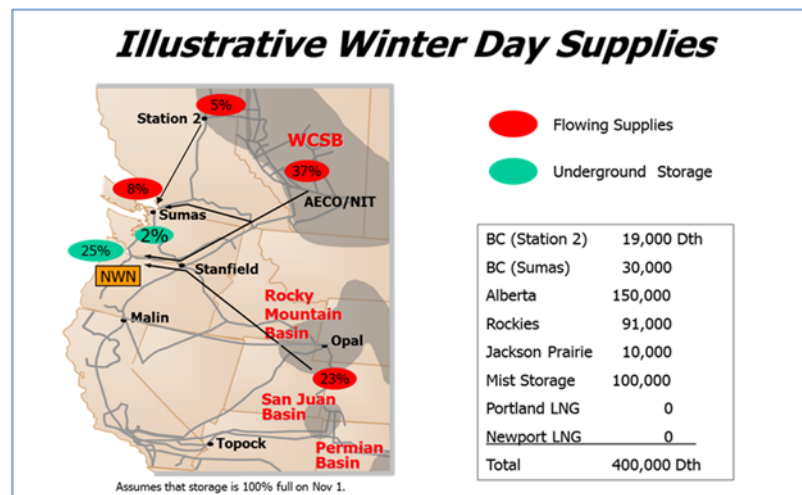
This year, there are no significant changes to the physical supply resource portfolio, but some items of note are:

- (1) Cold weather during the 2016/17 winter provided many opportunities to use segmented capacity as a resource, and its performance justifies its continued inclusion in the Company's resource portfolio;

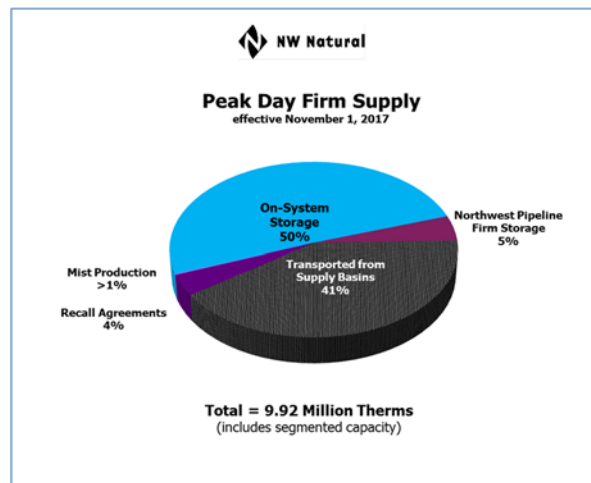
- (2) Updated load forecasts show that customer growth is being offset by lower usage per customer, such that new resources to bring more supplies to the Company's system are not needed for the coming PGA year;
- (3) The previously identified trend of rising heat content has not abated, leading to slightly higher deliverability from the Portland LNG plant and slightly more working gas capacity for utility customers at Mist;
- (4) Operational issues have reduced somewhat the working gas capacities of the Portland and Newport LNG plants; and
- (5) The Company is participating in an expansion of the T-South pipeline system in British Columbia, which will allow more purchases at Station 2 in lieu of Sumas and potentially Alberta and the Rockies. The analysis that led to participation in this expansion will be included in the Company's IRP Update filing later this summer. Since this expansion will not be in service until at least November 1, 2020, it has no impact on this or the next two PGA filings.

The Company's portfolio continues to reflect the gas reserves purchased under the agreement with Encana approved by the OPUC in 2011 with Encana. That agreement was amended in March 2014 and seven new gas wells were drilled with the successor company Jonah Energy LLC. This PGA continues to reflect the approved regulatory treatment for both sets of reserves. As a reminder, the seven Jonah Energy wells have an approved regulatory treatment that is different from the reserves obtained under the original program with Encana, but all of the gas reserve volumes essentially function as a financial tool, i.e., they displace an identical volume of financial derivatives that the Company otherwise would have executed. For the purposes of this filing, the Encana and Jonah Energy gas reserve volumes have no impact on the company's physical supply portfolio.

Using its mix of transportation and storage resources, the company achieves the following profile on a typical winter day.



Should its "design" peak day occur, all physical resources would be used in the following proportions (607,000 therms/day of segmented capacity is included):



A summary of the company's physical supply resources is provided in Tables 1 through 5.

Regarding physical supply purchasing, NW Natural will have contracts with suppliers for 550,000 therms per day of firm deliveries on a daily basis throughout the upcoming November 2017 through October 2018 period. This reflects the relatively stable daily component of NWN's demand, i.e., water heater and other non-space heating loads that are not seasonal in nature. This has been reduced slightly from last year to ensure we are not over-committed during the summer months.

For the November 2017 through March 2018 heating season, NW Natural will have contracts for an additional 1.25 million therms/day of supply under baseload agreements, and another 100,000 therms/day under peaking ("swing") contracts in the supply basins. This reflects the higher consumption of customers during those months. Buying under term supply contracts lessens the need to rely extensively on the spot market during periods of high demand when competition for supplies may be intense. The baseload contracts thus have a maximum total of 1.80 million therms/day (0.55 million year-round plus 1.25 million winter season) that are purchased on a take-or-pay basis. The remaining 0.10 million therms/day of swing gas is made available to NWN on a daily basis in exchange either for payment of a fixed "reservation" charge or for equivalent value in the form of put options during the summer months. These swing contracts have no minimum daily, monthly or seasonal purchase requirement, but they provide additional daily supply flexibility, which is especially valuable since winter weather can fluctuate rapidly between mild and cool temperatures, resulting in rapidly changing customer requirements.

This means between 1.53 and 1.63 million therms/day of firm upstream capacity could be available during the heating season for spot (one month and shorter duration) purchases as and when needed. And additional therms could be purchased on the spot market if the segmented capacity is available and utilized. Accordingly, on days when all upstream capacity is in use, purchases would be split among three categories – year-round contracts, winter term contracts and spot purchases, with spot gas comprising the largest component.

5. Financial resources for the portfolio (derivatives and other financial arrangements)

NWN "swaps" monthly index prices for fixed prices and other price structures through the use of financial instruments in order to increase price stability across the year. Volumes in storage, including any supply-basin storage arrangements, provide another form of hedging. In addition, gas reserves provide a hedge for Oregon customers in a completely different form.

Overall, NW Natural's target this year is to financially hedge the prices of approximately 49% of its expected annual sales requirements for the upcoming 12-month period commencing November 1st. Gas reserves are expected to account for another 6% of hedge volumes. Storage gas (which is purchased on the spot market) will account for another 19%, and local Mist gas production (which is indexed to our average gas purchase cost) adds another 1%. The remaining 25% of our annual purchase volumes, when combined with our purchases for storage, means about 45% of NW Natural's total volumes are purchased on an unhedged basis.

Financial hedging targets are set by an executive level oversight committee within the Company - the Gas Acquisition Strategy & Policies (GASP) Committee - and could change from time-to-time in reaction to market conditions or other factors as the year progresses.

In addition to financial swaps, the Company's derivative policies allow the use of financial options (puts and calls) to limit exposure to gas price fluctuations. For example, these instruments can be used in combination in order to "collar" the price of gas for specific purchases.

The Company's Gas Supply department performs the actual derivative transactions, while separate individuals, reporting to different executives, oversee the risk management of the hedging program such as approving counterparties and determining credit limits.

[START CONFIDENTIAL]

[REDACTED]

[REDACTED]

[REDACTED]

[END CONFIDENTIAL]

6. Storage resources

NWN relies on four storage facilities and one supply-basin storage arrangements in Alberta to balance its supply portfolio and meet customer requirements. Mist, Portland LNG (also known as Gasco) and Newport LNG are owned and operated by the company. NWN contracts with Northwest Pipeline for service at the Jackson Prairie underground facility in Washington state. The Alberta supply-basin storage arrangement is with J. Aron & Company (a subsidiary of Goldman Sachs).

Storage provides the following benefits to customers:

- a. Avoids the need to subscribe to year-round interstate pipeline capacity to meet winter season loads. This benefit applies to the storage located on NW Natural's system, and partially applies to Jackson Prairie storage, which is eligible for a Northwest Pipeline transportation service that is less expensive than normal year-round firm service. This benefit does not apply to storage located in the supply basins such as Alberta
- b. Allows more gas purchasing during the non-heating season, when prices are typically lower, instead of heating season periods when prices typically peak. Supply-basin storage is pursued when this potential benefit is sufficient to offset the cost of the storage service.
- c. Provides diversity of supply and gas movement to and through NWN's service territory, improving overall reliability.
- d. Helps balance daily demand with supplies, reducing the potential for imbalance penalties with upstream pipelines.
- e. Provides flexibility to take advantage of daily, monthly and seasonal variations in gas pricing, either directly by NWN or through its optimization arrangement.

Additional benefits attributable to Mist have been created through the development of an interstate storage service starting back in 2001. For example, rather than large “lumpy” resource additions requiring years of preparation, the “pre-build” of interstate storage service provides the ability to time and size incremental Mist capacity to a degree not achievable through typical resource development. The 300,000 therm/day Mist recall that occurred in 2015 was a perfect example since it could be sized to replace a portion of the terminated Plymouth capacity, rather than having to equal the size of an entire Mist reservoir/expansion project. And revisions to the customer load forecast have meant that previously planned storage additions for the utility could be deferred with multiple benefits to customers, e.g., rate base additions are deferred while revenue sharing from the interstate storage service continues.

More information on the company’s storage resources is provided in Table 3 and the workpapers.

Supporting information to IV.2.b.4

TABLE 1
NW Natural Firm Off-System Gas Supply Contracts
for the 2017-2018 Tracker Year

| Supply Location | Duration | Baseload Quantity (Dth/day) | Swing Quantity (Dth/day) | Contract Termination Date |
|------------------------------|----------|--------------------------------|-----------------------------|------------------------------|
| British Columbia: | | | | |
| ConocoPhillips (Canada) | Nov-Mar | 5,000 | | 3/31/2018 |
| J. Aron | Nov-Mar | 5,000 | | 3/31/2018 |
| J. Aron | Nov-Mar | 5,000 | | 3/31/2018 |
| <i>Pending</i> | Nov-Mar | 15,000 | | 3/31/2018 |
| <i>Pending</i> | Nov-Oct | 10,000 | | 10/31/2018 |
| Alberta: | | | | |
| ConocoPhillips (Canada) | Nov-Mar | 5,000 | | 3/31/2018 |
| TD Energy | Nov-Mar | 5,000 | | 3/31/2018 |
| J. Aron | Nov-Mar | 5,000 | | 3/31/2018 |
| Enstor Energy Services | Nov-Mar | 5,000 | | 3/31/2018 |
| Powerex | Nov-Oct | 5,000 | | 10/31/2018 |
| Suncor Energy | Nov-Mar | 5,000 | | 3/31/2018 |
| <i>Pending</i> | Nov-Oct | 10,000 | | 10/31/2018 |
| <i>Pending</i> | Nov-Mar | 25,000 | | 3/31/2018 |
| Rockies: | | | | |
| Anadarko Energy Services | Nov-Mar | 5,000 | | 3/31/2018 |
| Citadel Energy Marketing | Nov-Oct | 5,000 | | 10/31/2018 |
| Citadel Energy Marketing | Nov-Oct | 5,000 | | 10/31/2018 |
| Macquarie Energy | Nov-Mar | 5,000 | | 3/31/2018 |
| Ultra Resources | Nov-Mar | 10,000 | | 3/31/2018 |
| J. Aron | Nov-Mar | | 10,000 | 3/31/2018 |
| J. Aron | Apr-Oct | | 10,000 | 10/31/2018 |
| <i>Pending</i> | Nov-Oct | 20,000 | | 10/31/2018 |
| <i>Pending</i> | Nov-Mar | 25,000 | | 3/31/2018 |
| Total, November-March | | 180,000 | 10,000 | |
| Total, April-October | | 55,000 | 10,000 | |

Notes:

- Contract quantities represent deliveries into upstream pipelines. Accordingly, quantities delivered into NW Natural's system are slightly less due to upstream pipeline fuel consumption.
- Nov-Mar "Swing" contracts represent physical call options at NWN's discretion, while the Apr-Oct "Swing" contracts represent physical put options at the supplier's discretion.

Supporting information to IV.2.b.4

TABLE 2
NW Natural Firm Transportation Capacity
for the 2017-2018 Tracker Year

| Pipeline and Contract | Contract Demand (Dth/day) | Termination Date |
|---|------------------------------|------------------|
| Northwest Pipeline: | | |
| Sales Conversion (#100005) | 214,889 | 10/31/2025 |
| 1993 Expansion (#100058) | 35,155 | 9/30/2044 |
| 1995 Expansion (#100138) | 102,000 | 10/31/2020 |
| Occidental cap. acq. (#139153) | 1,046 | 10/31/2024 |
| Occidental cap. acq. (#139154) | 4,000 | 3/31/2025 |
| International Paper cap. acq. (#138065) | 4,147 | 10/31/2024 |
| March Point cap. acq. (#136455) | <u>12,000</u> | 12/31/2046 |
| Total NWP Capacity | 373,237 | |
| less recallable release to - Portland General Electric | <u>(30,000)</u> | 10/31/2018 |
| Net NWP Capacity | 343,237 | |
| TransCanada - GTN: | | |
| Sales Conversion | 3,616 | 10/31/2023 |
| 1993 Expansion | 46,549 | 10/31/2023 |
| 1995 Rationalization | <u>56,000</u> | 10/31/2021 |
| Total GTN Capacity | 106,165 | |
| TransCanada - Foothills: | | |
| 1993 Expansion | 47,727 | 10/31/2018 |
| 1995 Rationalization | 57,417 | 10/31/2018 |
| Engage Capacity Acquisition | 3,708 | 10/31/2018 |
| 2004 Capacity Acquisition | <u>48,669</u> | 10/31/2018 |
| Total Foothills Capacity | 157,521 | |
| TransCanada - NOVA: | | |
| 1993 Expansion | 48,135 | 10/31/2020 |
| 1995 Rationalization | 57,909 | 10/31/2020 |
| Engage Capacity Acquisition | 3,739 | 10/31/2020 |
| 2004 Capacity Acquisition | <u>49,138</u> | 10/31/2020 |
| Total NOVA Capacity | 158,921 | |
| T-South Capacity (through Tenaska) | 19,000 | 10/31/2018 |
| Southern Crossing Pipeline | 48,000 | 10/31/2020 |

Notes:

1. All of the above agreements continue year-to-year after termination at NW Natural's sole option except for PGE, which requires mutual agreement to continue, and the T-South contract, which is through a 2-year contract with Tenaska.
2. The Southern Crossing contract is denominated in volumetric units; hence the Dth units shown are an approximation.
3. The numbers shown for the 1993 Expansion contracts on GTN and Foothills are for the winter season (Oct-Mar) only. Both contracts decline during the summer season (Apr-Sep) to approximately 30,000 Dth/day.
4. Segmented capacity has not been included in this table.
5. T-South capacity does not include the new T-South Expansion contract of approximately 25,000 Dth/day, which will begin no earlier than November 1, 2020.

Supporting information IV.2.b4

TABLE 3
NW Natural Firm Storage Resources
for the 2017-2018 Tracker Year

| Facility | Max. Daily Rate(Dth/day) | Max. Seasonal Level (Dth) | Termination Date |
|---------------------------------------|---------------------------------|----------------------------------|-------------------------|
| Jackson Prairie: | | | |
| SGS-2F | 46,030 | 1,120,288 | Upon 1-year notice |
| TF-2 (primary firm portion) | 23,038 | 839,046 | Upon 1-year notice |
| TF-2 (primary firm portion) | 9,467 | 281,242 | Upon 1-year notice |
| TF-1 | 13,525 | n/a | 10/31/2023 |
| Firm On-System Storage Plants: | | | |
| Mist (reserved for core) | 305,000 | 11,266,191 | n/a |
| Portland LNG Plant | 130,680 | 490,050 | n/a |
| Newport LNG Plant | 65,340 | 827,640 | n/a |
| Total On-System Storage | 501,020 | 12,583,881 | |
| Total Firm Storage Resource | 547,050 | 13,704,169 | |

Notes:

1. The SGS-2F and TF-2 contracts have a unilateral annual evergreen provision (continuation at NW Natural's sole option), while the TF-1 contract requires mutual consent with Northwest Pipeline to continue after the indicated termination date.
2. The TF-2 contracts also contain additional "subordinated" firm service of 9,586 Dth/day on the first agreement listed above and 3,939 Dth/day on the second agreement. The subordinated service is NOT included in NW Natural's peak day planning.
3. On-system storage peak deliverability is based on design criteria, for example, Mist is at least 50% full.
4. Mist numbers pertain to the portion reserved for core utility service per the Company's Integrated Resource Plan. Additional capacity and deliverability at Mist have been contracted under varying terms to Interstate/Intrastate storage customers.
5. The Dth numbers for Mist, Newport LNG and Portland LNG are approximate in that they are converted from Mcf volumes, and so depend on the heat content of the stored gas. The current heat content used for Mist is 1069 Btu/cf. The current heat content used for Newport and Portland LNG is 1089 Btu/cf.
6. Newport tank capacity de-rated from 1 Bcf pending CO2 removal project.
7. Due to an ongoing Engineering analysis of the Portland LNG tank, liquifaction will be limited to 75% of the tank's capacity.
8. The Company's Plymouth-related contracts terminated on October 31, 2015, so they are no longer reflected in this table.
9. NW Natural has a supply-basin storage contract in Alberta that is NOT included in this table to avoid double-counting resources because its deliverability relies on portions of the same upstream pipeline capacity already included in Table 2. This contract is with:

J. Aron & Company – 1,530,000 Dth

Supporting information IV.2.b4

TABLE 4
NW Natural Other Resources: Recall Agreements, Citygate Deliveries and Mist Production
for the 2017-2018 Tracker Year

| Type | Max. Daily Rate (Dth/day) | Max. Annual Recall (days) | Termination Date |
|-----------------------------|------------------------------|------------------------------|--------------------|
| Recall Agreements: | | | |
| PGE | 30,000 | 30 | 10/31/2018 |
| International Paper | 8,000 | 40 | Upon 1-year notice |
| Georgia Pacific-Halsey Mill | 1,000 | 15 | Upon 1-year notice |
| Total Recall Resource | 39,000 | | |
| Citygate Deliveries: | | | |
| None | - | | |
| Mist Production: | | | |
| Enerfin Resources | ≈2,000 | n/a | Life of the wells |

Notes:

1. There are a variety of terms and conditions surrounding the recall rights under each of the above agreements, but they all include delivery of the gas to NW Natural's system.
2. Mist production is currently flowing at roughly the figure shown above. Flows vary as new wells are added and older wells deplete. NW Natural's obligation is to buy gas from existing wells through the life of those wells.

TABLE 5
NW Natural Peak Day Resource Summary
for the 2017-2018 Tracker Year

| Resource Type | (Dth/day) |
|--|----------------|
| Net Deliverability over Upstream Pipeline Capacity | 343,237 |
| Off-System Storage (Jackson Prairie only) | 46,030 |
| On-System Storage (Mist, Portland LNG and Newport LNG) | 501,020 |
| Recallable Capacity and Supply Agreements | 39,000 |
| Citygate Deliveries | - |
| Nominal Mist Production Gas | 2,000 |
| Segmented Capacity (not primary firm) | 60,700 |
| Total Peak Day Resources | 991,987 |

Notes:

1. The design firm sales peak day forecast for 2017-18 is 973,144 Dth as updated by Strategic Planning on 7/6/2017.
2. Per 2016 IRP draft filed 8/26/2016 (specifically page 3.19), Segmented Capacity currently is included as a firm resource until 11/1/2020.
3. Since firm resources (including Segmented Capacity) exceed the design peak day firm sales forecast, Citygate Deliveries are not being pursued for this tracker year.

7. Forecasted annual and peak demand used in the current PGA portfolio, with and without programmatic and non-programmatic demand response, with explanation

NW Natural includes *realized* demand response savings in forecasted annual and peak demand by updating use per customer coefficients prior to the annual PGA filing. The updated use per customer coefficient reflects demand measures actually taken in the previous year. Because our ability to accurately forecast annual demand savings is relatively uncertain, we do not include projected demand measures in our forecasted annual and peak demand.

| | 2017/2018 |
|---|------------------|
| Forecast Annual Demand (therms) | 728,507,577 |
| Forecast Peak Demand (therms) - Normal | 4,235,612 |
| Forecast Peak Demand (therms) - Design | 9,751,743 |
| | |
| Forecast DSM Annual (therms) | 0 |
| Forecast DSM Peak (therms) - Design Peak | 0 |
| | |
| Forecast Annual Demand with Forecast DSM | 728,507,577 |
| Forecast Peak Demand with Forecast DSM - Normal | 4,235,612 |
| Forecast Peak Demand with Forecast DSM - Design | 9,751,743 |

Note: As of this filing date, the DSM data was not available from the Energy Trust.

8. Forecasted annual and peak demand used in the current PGA portfolio, with and without effects from gas supply incentive mechanisms, with explanation.

Our forecasted annual and peak demand is not impacted by gas supply incentive mechanisms.

9. Summary of portfolio documentation provided

See Index.

Section V.1 - Physical Gas Supply

a) For each physical natural gas supply resource that is included in a utility's portfolio (except spot purchases) upon which the current PGA is based, the utility should provide the following:

1. Pricing for the resource, including the commodity price and, if relevant, reservation charges.

See Tables 1-4 below.

2. For new transactions and contracts with pricing provisions entered into since the last PGA: competitive bidding process for the resource. This should include number of bidders, bid prices utility decision criteria in selecting a "winning" bid, and any special pricing or delivery provisions negotiated as part of the bidding process

See Tables 1-4 below.

3. Brief explanation of each contract's role within the portfolio.

See Tables 1-4 below. **[START HIGHLY CONFIDENTIAL]**

TABLE 1

| Northwest Natural Gas Company PGA Filing Guidelines November 1, 2017 - October 31, 2018 Physical Natural Gas term contracts All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies Approved Counterparties all have executed NAESB contracts with NW Natural Rocky Mountain Supply contracts | | | | | | | | | | |
|---|------------|------------|-----------------|-----------------------|-----------------------------|--------------------------|-------------------------------------|------------------------|---------------------------------------|-------------------------------------|
| Supplier | Term Start | Term End | Commodity Price | Published Index | Baseload Volume/Day in Dths | Swing Volume/Day in Dths | Swing Reservation Fee cents/Dth/day | Contractual Conditions | Default Receipt Pt. Purchase Location | Internal Reference No. |
| Citadel Energy Marketing LLC (1) | 11/1/2017 | 10/31/2018 | [REDACTED] | IFGMR-NWP Rockies FOM | 5,000 | | | | Rocky Mountain Pool | 17-AL-18 |
| Citadel Energy Marketing LLC (2) | 11/1/2017 | 10/31/2018 | [REDACTED] | IFGMR-NWP Rockies FOM | 5,000 | | | | Opal | 17-AL-22 |
| Anadarko Energy Services Company (3) | 11/1/2017 | 3/31/2018 | [REDACTED] | IFGMR-NWP Rockies FOM | 5,000 | | | | Rocky Mountain Pool | 17-AL-8 |
| Macquarie Energy, LLC (4) | 11/1/2017 | 3/31/2018 | [REDACTED] | IFGMR-NWP Rockies FOM | 5,000 | | | | Opal | 17-AL-13 |
| Ultra Resources (5) | 11/1/2017 | 3/31/2018 | [REDACTED] | IFGMR-NWP Rockies FOM | 10,000 | | | | Opal | 17-MM-29 |
| PENDING: NGR's: 15,000 Dths One Year Baseload: 5,000 Dths Winter Baseload: 25,000 Dths | | | | | | | | | | |
| J. Aron & Company (6) | 11/1/2017 | 3/31/2018 | [REDACTED] | IFGMR-NWP Rockies FOM | | | | | | up to 10,000 NW Natural Call Option |
| J. Aron & Company (6) | 4/1/2018 | 10/31/2018 | [REDACTED] | IFGMR-NWP Rockies FOM | | | | | | up to 10,000 J. Aron Put Option |
| Transactions for new PGA year | | | | | | | | | | |
| Bidding Process Information | | | # of Bidders | Range of bids. | Winning Bid Criteria | | | | | |
| (1) Rocky Mountain Pool | 5 | [REDACTED] | | | Price | | | | | |
| (2) Opal | 5 | [REDACTED] | | | Price | | | | | |
| (3) Rocky Mountain Pool | 5 | [REDACTED] | | | Price | | | | | |
| (4) Opal | 5 | [REDACTED] | | | Price | | | | | |
| (5) Opal | 3 | [REDACTED] | | | Price | | | | | |
| (6) Rocky Mountain Pool | 3 | [REDACTED] | | | Price | | | | | |

TABLE 2

| Northwest Natural Gas Company PGA Filing Guidelines | | HIGHLY CONFIDENTIAL SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337 | | | | | | | | | |
|--|------------|--|-----------------|-------------------------------|------------------------------|---------------------------|-------------------------------------|------------------------|---------------------------------------|------------------------|--|
| November 1, 2017 - October 31, 2018 Physical Natural Gas term contracts | | | | | | | | | | | |
| All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies Approved Counterparties all have executed NAESB contracts with NW Natural | | | | | | | | | | | |
| Huntingdon, BC Supply contracts | | | | | | | | | | | |
| Supplier | Term Start | Term End | Commodity Price | Published Index | Baseload Volume/Day in Dth's | Swing Volume/Day in Dth's | Swing Reservation Fee cents/Dth/day | Contractual Conditions | Default Receipt Pt. Purchase Location | Internal Reference No. | |
| J. Aron & Company (1) | 11/1/2017 | 3/31/2018 | | IFGMR-NWP Canadian Border FOM | 5,000 | | | | Huntingdon | 17-AL-11 | |
| ConocoPhillips Canada (2) | 11/1/2017 | 3/31/2018 | | IFGMR-NWP Canadian Border FOM | 5,000 | | | | Huntingdon | 17-AL-24 | |
| PENDING: Winter Baseload: 15,000 Dths | | | | | | | | | | | |
| Transactions for new PGA year | | | | | | | | | | | |
| Bidding Process Information | | # of Bidders | Range of bids. | | Winning Bid Criteria | | | | | | |
| (1) Huntingdon | | 5 | | | Price | | | | | | |
| (2) Huntingdon | | 5 | | | Price | | | | | | |

TABLE 3

| Northwest Natural Gas Company PGA Filing Guidelines | | HIGHLY CONFIDENTIAL SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337 | | | | | | | | | |
|--|------------|--|-----------------|--------------------|------------------------------|---------------------------|-------------------------------------|------------------------|---------------------------------------|------------------------|--|
| November 1, 2017 - October 31, 2018 Physical Natural Gas term contracts | | | | | | | | | | | |
| All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies Approved Counterparties all have executed NAESB contracts with NW Natural | | | | | | | | | | | |
| Huntingdon, BC Supply contracts | | | | | | | | | | | |
| Supplier | Term Start | Term End | Commodity Price | Published Index | Baseload Volume/Day in Dth's | Swing Volume/Day in Dth's | Swing Reservation Fee cents/Dth/day | Contractual Conditions | Default Receipt Pt. Purchase Location | Internal Reference No. | |
| J. Aron & Company (1) | 11/1/2017 | 3/31/2018 | | CGPR AECO FOM (7A) | \$US/Dth | 5,000 | | | Station 2 | 17-AL-29 | |
| PENDING One Year Baseload 10,000 Dths | | | | | | | | | | | |
| Transactions for new PGA year | | | | | | | | | | | |
| Bidding Process Information | | # of Bidders | Range of bids. | | Winning Bid Criteria | | | | | | |
| (1) Station 2 | | 6 | | | Price | | | | | | |

TABLE 4

| Northwest Natural Gas Company PGA Filing Guidelines | | HIGHLY CONFIDENTIAL SUBJECT TO MODIFIED PROTECTIVE ORDER 10-337 | | | | | | | |
|--|------------|--|-----------------------|-----------------------------|------------------------------|---------------------------|------------------------|------------------------|--|
| November 1, 2017 - October 31, 2018 Physical Natural Gas term contracts | | | | | | | | | |
| All contracts are with Approved Counterparties per Exhibit "G" - NW NATURAL Gas Supply Risk Management Policies Approved Counterparties all have executed NAESB contracts with NW Natural | | | | | | | | | |
| Aeco-NIT Supply contracts | | | | | | | | | |
| Supplier | Term Start | Term End | Commodity Price | Published Index | Baseload Volume/Day in Dth's | Swing Volume/Day in Dth's | Contractual Conditions | Internal Reference No. | |
| Powerex (1) | 11/1/2017 | 10/31/2018 | | CGPR AECO FOM (7A) \$US/Dth | 5,000 | | | 17-MM-25 | |
| ConocoPhillips Canada (2) | 11/1/2017 | 3/31/2018 | | CGPR AECO FOM (7A) \$US/Dth | 5,000 | | | 17-MM-16 | |
| TD Energy Trading, Inc. (3) | 11/1/2017 | 3/31/2018 | | CGPR AECO FOM (7A) \$US/Dth | 5,000 | | | 17-AL-15 | |
| J. Aron & Company (4) | 11/1/2017 | 3/31/2018 | | CGPR AECO FOM (7A) \$US/Dth | 5,000 | | | 17-AL-16 | |
| Enstor Energy LLC (5) | 11/1/2017 | 3/31/2018 | | CGPR AECO FOM (7A) \$US/Dth | 5,000 | | | 17-MM-26 | |
| Suncor (6) | 11/1/2017 | 3/31/2018 | | CGPR AECO FOM (7A) \$US/Dth | 5,000 | | | 17-MM-27 | |
| PENDING: One Year Baseload: 10,000 Dths Winter Baseload: 25,000 Dths | | | | | | | | | |
| Transactions for new PGA year | | | | | | | | | |
| Bidding Process Information | | # of Bidders | Range of bids. | Winning Bid Criteria | | | | | |
| (1) | | 3 | | Price | | | | | |
| (2) | | 4 | | Price | | | | | |
| (3) | | 5 | | Price | | | | | |
| (4) | | 5 | | Price | | | | | |
| (5) | | 3 | | Price | | | | | |
| (6) | | 3 | | Price | | | | | |

[END HIGHLY CONFIDENTIAL]

b) For purchases of physical natural gas supply resources from the spot natural gas market included in the portfolio at the time of the filing of the current PGA or after that filing, the utility should provide the following:

1. An explanation of the utility's spot purchasing guidelines, the data/information generally reviewed and analyzed in making spot purchases, and the general process through which such purchases are complete by the utility.
 1. The purchasing of baseload and spot supplies for the 2017-2018 PGA follows the Gas Acquisition Plan as prepared by the Gas Supply department and overseen by the company's Gas Acquisition Strategy and Policies (GASP) Committee. GASP members include the company's CEO, CFO and other senior company management.
 2. In our gas purchasing for 2017-2018, we target diversity of supply on a regional basis and among approved counterparties, as listed in the company's Gas Supply Risk Management Policies. The advantage of regional diversity is the opportunity to manage purchases to capture the lowest cost while maintaining a diversity of suppliers and avoiding over-reliance on any one trading point or counterparty.
 3. Diversity of contracts in the portfolio is determined by the forecasted usage of NW Natural customers.
 - a. One year and greater baseload (take or pay) contract volumes are meant to meet low end of sales requirements while avoiding the potential for excess supply that might have to be sold at a loss when sales volumes are low. Pricing is comparable to shorter term contracts and the administrative needs are a bit simpler.
 - b. November – March winter term contracts are aligned to meet the forecasted seasonal increase during the heating season and are divided between baseload and winter call option ("swing") contracts. This helps minimize the exposure to purchasing large volumes of high priced spot gas during cold weather events.

- c. April – October summer put option contracts are tied to winter call option contracts to capture a discounted monthly index price and avoid payment of a reservation fee. The volume of the put option contracts is kept to a minimum to avoid over supply during the summer months when added to year-round term volumes.
- d. Spot purchases are used to fill in requirements on a very short-term basis, from one day up to one month, throughout the PGA year. One month spot purchases are negotiated to capture the best monthly index pricing using either the publication *Inside FERC's Gas Market Report* for Rockies and Sumas purchases, or the publication *Canadian Gas Price Reporter* for Canadian purchases in Alberta. Daily spot purchasing utilizes either a daily index (in the case of Rocky Mountain or Sumas supply as published in *Gas Daily*) or a fixed price in U.S. dollars as negotiated directly with the suppliers. The electronic trading platform Intercontinental Exchange (ICE) provides real-time pricing for Rocky Mountain, Sumas, Station 2 and Alberta supplies as a reference tool for such price negotiations

2. Any contract provisions that materially deviate from the standard NAESB contract.

None for the vast bulk of the company's purchases made in the Rockies and western Canada.

There is a small percentage (approximately 1%) of the company's purchases sourced from the Mist field, i.e., native gas that continues to be locally produced there. These purchases do not rely on a NAESB contract but instead on a custom-written contract that dates back to 1995. As an example, gas quality and measurement is a relatively simple matter in the NAESB contract because the gas needs to conform to the tariff provisions of one or more applicable interstate pipelines, but it requires a lot more attention for Mist production gas because there are no transporting interstate pipelines over which the gas is delivered to the company.

[START HIGHLY CONFIDENTIAL]

Section V.2 - Hedging

The utility should clearly identify by type, contract, counterparty, and pricing point both the total cost and the cost per volume unit of each financial hedge included in its portfolio.

| 2017-2018 FINANCIAL HARD HEDGES (counterparty does not own option) | | | | | | | | | | | | |
|--|-----------------|--------------|-------------------|--------------------|---------------------|--------------|--------------|-------------------|--|--|--|------------------------|
| Trade Date | Internal Ref. # | Counterparty | Associated Supply | Supply or Ref. Pt. | Term | 2017-18 Days | Daily Volume | Trade Volume | | | | Including Multi-Traker |
| 26-Mar-15 | 2015-7 | | | Sumas | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 10-Apr-15 | 2015-12 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 20-Apr-15 | 2015-15 | | | Sumas | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 30-Apr-15 | 2015-19 | | | Rockies | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 22-May-15 | 2015-22 | | | Sumas | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 27-May-15 | 2015-24 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 29-May-15 | 2015-27 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 4-Jun-15 | 2015-28 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 30-Jun-15 | 2015-33 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 18-Sep-15 | 2015-44 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 25-Sep-15 | 2015-46 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 1-Oct-15 | 2015-50 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 21-Oct-15 | 2015-53 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 27-Oct-15 | 15-MM-22 | | | AECO | Nov-Mar (2015-2018) | 151 | 2,500 | 377,500 | | | | 1,135,000 |
| 15-Mar-16 | 2016-6 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 22-Mar-16 | 2016-10 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 29-Mar-16 | 2016-12 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 31-Mar-16 | 2016-15 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 11-Apr-16 | 2016-20 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 18-Apr-16 | 2016-22 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 20-Apr-16 | 2016-24 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 22-Apr-16 | 2016-26 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 25-Apr-16 | 2016-27 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 29-Apr-16 | 2016-30 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 10-May-16 | 2016-31 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 16-May-16 | 2016-33 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 18-May-16 | 2016-34 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 23-May-16 | 2016-36 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 27-May-16 | 2016-40 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 1-Jun-16 | 2016-41 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 14-Jun-16 | 2016-43 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 20-Jun-16 | 2016-44 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 30-Jun-16 | 2016-50 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 3-Oct-16 | 2016-86 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 18-Oct-16 | 2016-89 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 19-Oct-16 | 2016-70 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 20-Oct-16 | 2016-71 | | | AECO | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 26-Oct-16 | 2016-74 | | | Rockies | Nov-Mar (2016-2019) | 151 | 2,500 | 377,500 | | | | 1,132,500 |
| 22-Feb-17 | 2017-1 | | | Rockies | Oct | 31 | 5,000 | 155,000 | | | | 155,000 |
| 23-Feb-17 | 2017-2 | | | AECO | April | 30 | 10,000 | 300,000 | | | | 300,000 |
| 24-Feb-17 | 2017-3 | | | AECO | Oct | 31 | 10,000 | 310,000 | | | | 310,000 |
| 27-Feb-17 | 2017-4 | | | AECO | Sep-Oct | 61 | 5,000 | 305,000 | | | | 305,000 |
| 22-Mar-17 | 2017-5 | | | AECO | April | 30 | 10,000 | 300,000 | | | | 300,000 |
| 27-Mar-17 | 2017-6 | | | AECO | Oct | 31 | 10,000 | 310,000 | | | | 310,000 |
| 29-Mar-17 | 2017-7 | | | Rockies | Apr-June | 91 | 5,000 | 455,000 | | | | 455,000 |
| 30-Mar-17 | 2017-8 | | | AECO | Apr-June | 91 | 5,000 | 455,000 | | | | 455,000 |
| 10-Apr-17 | 2017-9 | | | AECO | Apr | 30 | 10,000 | 300,000 | | | | 300,000 |
| 19-Apr-17 | 2017-10 | | | Rockies | Nov-Jan (2017-2020) | 92 | 2,500 | 230,000 | | | | 690,000 |
| 20-Apr-17 | 2017-11 | | | AECO | Nov-Jan | 92 | 5,000 | 460,000 | | | | 460,000 |
| 21-Apr-17 | 2017-12 | | | AECO | Oct | 31 | 10,000 | 310,000 | | | | 310,000 |
| 24-Apr-17 | 2017-13 | | | Rockies | Nov-Jan (2017-2020) | 92 | 2,500 | 230,000 | | | | 230,000 |
| 26-Apr-17 | 2017-14 | | | Sumas | Nov-Mar (2017-2020) | 151 | 2,500 | 377,500 | | | | 377,500 |
| 27-Apr-17 | 2017-15 | | | Rockies | Apr-Oct | 214 | 5,000 | 1,070,000 | | | | 1,070,000 |
| 5-May-17 | 2017-16 | | | Rockies | Apr-Oct | 214 | 5,000 | 1,070,000 | | | | 1,070,000 |
| 9-May-17 | 2017-17 | | | Rockies | Nov-Jan (2017-2020) | 92 | 2,500 | 230,000 | | | | 230,000 |
| 16-May-17 | 2017-18 | | | AECO | Apr-Oct | 214 | 5,000 | 1,070,000 | | | | 1,070,000 |
| 19-May-17 | 2017-19 | | | Sumas | Nov-Mar (2017-2020) | 151 | 2,500 | 377,500 | | | | 377,500 |
| 23-May-17 | 2017-20 | | | AECO | Apr-Oct | 214 | 5,000 | 1,070,000 | | | | 1,070,000 |
| 24-May-17 | 2017-21 | | | Sumas | Nov-Mar (2017-2020) | 151 | 2,500 | 377,500 | | | | 377,500 |
| 25-May-17 | 2017-22 | | | Rockies | Nov-Jan (2017-2020) | 92 | 2,500 | 230,000 | | | | 230,000 |
| 2-Jun-17 | 2017-23 | | | Sumas | Nov-Mar (2017-2020) | 151 | 2,500 | 377,500 | | | | 377,500 |
| 6-Jun-17 | 2017-24 | | | AECO | Apr-Oct | 214 | 5,000 | 1,070,000 | | | | 1,070,000 |
| 13-Jun-17 | 2017-25 | | | Sumas | Nov-Mar (2017-2020) | 151 | 2,500 | 377,500 | | | | 377,500 |
| 23-Jun-17 | 2017-26 | | | AECO | Nov-Jan (2017-2018) | 92 | 5,000 | 480,000 | | | | 460,000 |
| 21-Jun-17 | 2017-27 | | | AECO | Nov-Jan (2017-2018) | 92 | 5,000 | 480,000 | | | | 460,000 |
| 26-Jun-17 | 2017-28 | | | Rockies | Nov-Jan (2017-2020) | 92 | 2,500 | 230,000 | | | | 230,000 |
| 28-Jun-17 | 2017-29 | | | Rockies | Nov-Jan (2017-2020) | 92 | 2,500 | 230,000 | | | | 230,000 |
| Total Hard Hedges | | | | | | | | 27,542,500 | | | | 56,727,500 |

| CONFIDENTIAL | | | | | | | | | | 2017-2018 FINANCIAL SOFT HEDGES (counterparty owns option) | | | | | |
|---|-----------------|--------------|-------------------|--------------------|------|------|--------------|--------------------|--|--|-------------------|--------------------------|------------|-----------------|----|
| Trade Date | Internal Ref. # | Counterparty | Associated Supply | Supply or Ref. Pt. | Term | Days | Daily Volume | Total Trade Volume | | | CALL STRIKE PRICE | | | | |
| Total Soft Hedges | | | | | | | | 0 | | | | | | | |
| Total Hard and Soft Hedges | | | | | | | | | | | | | | | |
| Total Baseload Hedges | | | | | | | | | | | | | Variance | \$0.00 | |
| Total Baseload Hedges including Index Adjustments | | | | | | | | | | | | | | | |
| Hedges by Counterparty: | | | | | | | | | | Hedges for Nov 2017 - Oct 2018 | | All Hedges Nov17 Forward | | NOTIONAL RANK * | |
| [REDACTED] | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 10 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 6 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 8 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 1 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 10 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 7 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 5 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 9 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 2 |
| | | | | | | | | | | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 4 |
| [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | [REDACTED] | 3 | | | | | | | | | | |

Counterparty is on hold. No hedge transactions permitted.
Counterparty is approved for hedges only through prompt tracker year.
Counterparty is approved for multi-tracker hedges.
*Notional Rank is used for risk diversity. When counterparties tie for the lowest offer, the deal goes to the counterparty with the lowest \$ notional value shown here. Notional values include all hedges in place for the prompt tracker year forward including extendible options and multi-year hedges.

[END HIGHLY CONFIDENTIAL]

Section V.3 - Load Forecasting

a. Customer count and revenue by month and class.

| | Customer Cnt Jul-16 | Revenue Jul-16 | Customer Cnt Aug-16 | Revenue Aug-16 | Customer Cnt Sep-16 | Revenue Sep-16 |
|--|------------------------|-------------------------|------------------------|-------------------------|------------------------|-------------------------|
| Total | 717,689 | \$ 27,374,264.78 | 717,691 | \$ 25,673,625.58 | 718,139 | \$ 27,110,227.10 |
| Oregon | 639,597 | 24,726,473.81 | 639,483 | 23,183,267.66 | 639,785 | 24,515,116.78 |
| Washington | 78,092 | 2,647,790.97 | 78,208 | 2,490,357.92 | 78,354 | 2,595,110.32 |
| Total Residential | 650,220 | 14,386,217.08 | 650,378 | 13,176,043.20 | 650,950 | 13,957,227.44 |
| Total Commercial | 66,294 | 8,660,321.21 | 66,136 | 8,061,223.07 | 66,009 | 8,487,512.69 |
| Total Industrial | 656 | 1,509,655.09 | 658 | 1,538,909.17 | 661 | 1,700,700.11 |
| Total Interruptible | 134 | 1,318,556.46 | 134 | 1,370,326.86 | 134 | 1,422,590.02 |
| Total Transportation - Commercial Firm | 165 | 204,032.06 | 165 | 201,479.48 | 165 | 221,100.98 |
| Total Transportation - Industrial Firm | 120 | 636,258.22 | 120 | 635,532.47 | 119 | 637,086.25 |
| Total Transportation - Interruptible | 100 | 659,224.66 | 100 | 690,111.33 | 101 | 684,009.61 |
| Unbilled Revenue | | (1,415,034.21) | | (90,243.65) | | 2,826,907.47 |
| Agency Fees | | | | | | |
| Net Balancing/Overrun | | 4,418.00 | | 753.00 | | 183.00 |
| Total Gas Operating Revenue | | \$ 25,963,648.57 | | \$ 25,584,134.93 | | \$ 29,937,317.57 |

| | Customer Cnt Oct-16 | Revenue Oct-16 | Customer Cnt Nov-16 | Revenue Nov-16 | Customer Cnt Dec-16 | Revenue Dec-16 |
|--|------------------------|------------------------|------------------------|-------------------------|------------------------|--------------------------|
| Total | 719,820 | \$37,031,959.62 | 722,599 | \$ 50,358,252.14 | 725,146 | \$ 96,493,979.87 |
| Oregon | 641,274 | 33,574,596.40 | 643,675 | 45,644,590.67 | 645,883 | 87,639,473.38 |
| Washington | 78,546 | 3,457,363.22 | 78,924 | 4,713,661.47 | 79,263 | 8,854,506.49 |
| Total Residential | 652,480 | 20,646,759.89 | 654,808 | 30,223,675.10 | 656,855 | 61,968,678.67 |
| Total Commercial | 66,160 | 10,921,872.45 | 66,607 | 14,579,424.56 | 67,109 | 28,087,598.52 |
| Total Industrial | 662 | 2,066,279.32 | 657 | 1,951,895.30 | 655 | 2,167,735.31 |
| Total Interruptible | 133 | 1,771,365.10 | 133 | 1,931,812.96 | 133 | 2,390,292.95 |
| Total Transportation - Commercial Firm | 165 | 263,238.48 | 168 | 303,153.60 | 169 | 400,652.40 |
| Total Transportation - Industrial Firm | 119 | 674,954.03 | 125 | 695,568.64 | 123 | 767,964.55 |
| Total Transportation - Interruptible | 101 | 687,490.35 | 101 | 672,721.98 | 102 | 711,057.47 |
| Unbilled Revenue | | 11,953,162.33 | | 16,112,738.91 | | 20,210,969.94 |
| Agency Fees | | | | | | |
| Net Balancing/Overrun | | 836.00 | | - | | 349,463.00 |
| Total Gas Operating Revenue | | \$48,985,957.95 | | \$ 66,470,991.05 | | \$ 117,054,412.81 |

| | Customer Cnt Jan-17 | Revenue Jan-17 | Customer Cnt Feb-17 | Revenue Feb-17 | Customer Cnt Mar-17 | Revenue Mar-17 |
|--|------------------------|--------------------------|------------------------|-------------------------|------------------------|-------------------------|
| Total | 727,388 | \$ 139,539,319.27 | 728,804 | \$ 110,793,822.36 | 730,067 | \$ 89,071,858.53 |
| Oregon | 647,831 | 124,907,598.30 | 649,043 | 99,590,568.21 | 650,077 | 80,155,392.82 |
| Washington | 79,557 | 14,631,720.97 | 79,761 | 11,203,254.15 | 79,990 | 8,916,465.71 |
| Total Residential | 658,839 | 88,862,604.75 | 660,241 | 69,824,566.27 | 661,217 | 55,246,777.73 |
| Total Commercial | 67,370 | 43,528,109.81 | 67,380 | 34,543,653.03 | 67,668 | 27,491,550.81 |
| Total Industrial | 653 | 2,582,918.37 | 659 | 2,371,923.82 | 660 | 2,174,315.17 |
| Total Interruptible | 132 | 2,629,946.11 | 131 | 2,297,781.37 | 131 | 2,382,286.52 |
| Total Transportation - Commercial Firm | 170 | 432,731.98 | 170 | 363,606.50 | 170 | 345,901.94 |
| Total Transportation - Industrial Firm | 124 | 791,218.48 | 123 | 730,593.26 | 123 | 734,089.34 |
| Total Transportation - Interruptible | 100 | 711,789.77 | 100 | 661,698.11 | 98 | 696,937.02 |
| Unbilled Revenue | | (6,126,765.33) | | (14,403,263.87) | | (5,697,782.80) |
| Agency Fees | | | | | | |
| Net Balancing/Overrun | | 36,681.00 | | 641.00 | | 2,704.00 |
| Total Gas Operating Revenue | | \$ 133,449,234.94 | | \$ 96,391,199.49 | | \$ 83,376,779.73 |

| | Customer Cnt Apr-17 | Revenue Apr-17 | Customer Cnt May-17 | Revenue May-17 | Customer Cnt Jun-17 | Revenue Jun-17 |
|--|------------------------|-------------------------|------------------------|-------------------------|------------------------|-------------------------|
| Total | 730,515 | \$ 69,102,798.57 | 730,852 | \$ 52,375,620.91 | 730,968 | \$ 23,855,236.59 |
| Oregon | 650,375 | 62,487,143.66 | 650,545 | 47,392,222.47 | 650,512 | 20,482,035.12 |
| Washington | 80,140 | 6,615,654.91 | 80,307 | 4,983,398.44 | 80,456 | 3,373,201.47 |
| Total Residential | 661,802 | 42,678,246.61 | 662,209 | 31,217,612.25 | 662,376 | 13,050,161.27 |
| Total Commercial | 67,530 | 20,832,694.57 | 67,461 | 15,921,979.37 | 67,410 | 7,260,926.73 |
| Total Industrial | 657 | 1,917,341.88 | 657 | 1,746,763.71 | 658 | 1,087,301.63 |
| Total Interruptible | 131 | 1,977,934.08 | 131 | 1,827,668.93 | 130 | 880,894.78 |
| Total Transportation - Commercial Firm | 170 | 318,789.58 | 171 | 257,921.98 | 170 | 231,104.51 |
| Total Transportation - Industrial Firm | 123 | 702,277.50 | 123 | 687,815.57 | 124 | 660,591.56 |
| Total Transportation - Interruptible | 102 | 675,514.35 | 100 | 715,859.10 | 100 | 684,256.11 |
| Unbilled Revenue | | (7,524,081.53) | | (11,337,861.56) | | (4,729,240.35) |
| Agency Fees | | | | | | |
| Net Balancing/Overrun | | - | | - | | 2,054.10 |
| Total Gas Operating Revenue | | \$ 61,578,717.04 | | \$ 41,037,759.35 | | \$ 19,128,050.34 |

b. Historical (five years) and forecasted (one year ahead) sales system physical peak demand.

| | 2017/2018 Forecasted | 2016/2017 | 2015/2016 | 2014/2015 | 2013/2014 | 2012/2013 |
|-----------------------------|-------------------------|-----------|-----------|-----------|-----------|-----------|
| System peak demand (therms) | 9,751,743 | 9,777,033 | 9,452,960 | 9,369,764 | 9,320,242 | 9,252,236 |

c. Historical (five years) and forecasted (one year ahead) sales system physical annual demand.

| Gas Year | Forecasted 2017/2018 | 2016/2017 | 2015/2016 | 2014/2015 | 2013/2014 | 2012/2013 |
|------------------------|----------------------|-------------|-------------|-------------|-------------|-------------|
| Annual Demand (therms) | 728,507,577 | 744,738,987 | 757,005,313 | 747,790,904 | 746,847,556 | 732,272,081 |

d. Historical (five years) and forecasted (one year ahead) sales system physical demand for each of the following:

1. Annual for each customer class

| Gas Year | Forecasted 2017/2018 | 2016/2017 | 2015/2016 | 2014/2015 | 2013/2014 | 2012/2013 |
|-----------------------------------|----------------------|-------------|-------------|-------------|-------------|-------------|
| Residential (therms) | 402,002,465 | 403,236,093 | 413,822,757 | 402,683,123 | 396,647,034 | 388,025,253 |
| Commercial (therms) | 242,981,349 | 249,799,490 | 251,595,828 | 248,351,476 | 245,792,366 | 234,253,226 |
| Industrial Firm (therms) | 32,457,949 | 32,943,487 | 32,420,945 | 34,513,268 | 33,853,619 | 37,619,102 |
| Industrial Interruptible (therms) | 51,065,814 | 58,759,917 | 59,165,782 | 62,243,048 | 70,554,536 | 64,343,014 |

2. Annual and monthly baseload.

| Gas Year | Forecasted 2017-2018 | 2016/2017 | 2015/2016 | 2014/2015 | 2013/2014 | 2012/2013 |
|-----------|-------------------------|---------------|-------------|-------------|-------------|-------------|
| November | 23,614,499.82 | 24,554,895.58 | 22,351,644 | 22,999,936 | 22,397,233 | 22,308,001 |
| December | 23,641,080.52 | 25,262,436.80 | 22,916,079 | 24,282,715 | 23,202,872 | 23,064,485 |
| January | 23,661,616.64 | 25,346,740.02 | 22,938,449 | 24,362,006 | 23,196,614 | 23,081,208 |
| February | 23,676,659.65 | 24,129,267.19 | 21,874,421 | 22,159,174 | 20,943,260 | 20,859,821 |
| March | 23,692,533.31 | 25,387,380.30 | 22,968,882 | 23,866,828 | 23,202,391 | 23,109,951 |
| April | 23,699,550.78 | 24,778,007.82 | 22,440,684 | 22,869,798 | 22,513,500 | 22,379,225 |
| May | 23,708,824.06 | 25,382,611.30 | 22,997,543 | 23,238,337 | 23,254,362 | 23,138,668 |
| June | 23,713,005.21 | 24,738,270.85 | 22,470,443 | 22,332,108 | 22,556,453 | 22,399,655 |
| July | 23,710,087.55 | 25,327,244.58 | 23,023,353 | 23,019,887 | 23,314,587 | 23,152,520 |
| August | 23,708,249.43 | 25,304,863.03 | 23,050,124 | 23,015,123 | 23,324,427 | 23,162,291 |
| September | 23,717,107.35 | 24,686,183.77 | 22,527,362 | 22,737,568 | 22,537,805 | 22,425,676 |
| October | 23,742,625.86 | 25,342,154.07 | 23,100,640 | 23,881,459 | 23,359,078 | 23,196,701 |
| Annual | 284,285,840 | 300,240,055 | 272,659,625 | 278,764,939 | 273,802,581 | 272,278,201 |

3. Annual and monthly non-baseload

| Gas Year | Forecasted 2017/2018 | 2016/2017 | 2015/2016 | 2014/2015 | 2013/2014 | 2012/2013 |
|-----------|-------------------------|-------------|-------------|-------------|-------------|-------------|
| November | 57,380,740 | 56,712,943 | 64,242,976 | 62,486,370 | 62,248,709 | 61,226,239 |
| December | 93,647,405 | 91,432,786 | 98,795,855 | 96,475,524 | 95,405,022 | 90,481,345 |
| January | 88,933,839 | 86,488,891 | 92,054,676 | 90,486,111 | 91,382,451 | 86,593,507 |
| February | 67,127,899 | 76,659,460 | 74,851,835 | 71,804,677 | 72,204,387 | 69,575,367 |
| March | 54,005,602 | 52,474,527 | 59,855,292 | 58,202,117 | 58,522,284 | 56,408,082 |
| April | 32,492,116 | 32,605,411 | 40,203,184 | 38,491,513 | 38,745,792 | 37,886,663 |
| May | 16,233,535 | 15,547,950 | 18,600,362 | 17,127,632 | 17,039,845 | 15,982,505 |
| June | 4,731,141 | 4,924,141 | 4,336,063 | 3,488,689 | 4,181,989 | 3,799,251 |
| July | 889,329 | 380,842 | 304,475 | 25,201 | 707,612 | 393,204 |
| August | 593,417 | 280,995 | 0 | - | 769,863 | 358,541 |
| September | 3,450,139 | 3,237,113 | 2,211,685 | 2,291,298 | 3,220,573 | 1,673,213 |
| October | 24,736,573 | 23,753,874 | 28,889,285 | 28,146,833 | 28,616,445 | 27,584,476 |
| Annual | 444,221,737 | 444,498,932 | 484,345,688 | 469,025,965 | 473,044,975 | 451,962,394 |

4. Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update.

V.3.d. Historical (five years), and forecasted (one year ahead) sales system physical demand for each of the following:
4. Annual and monthly for the geographic regions utilized by each LDC in its most recent IRP or IRP update

| 2017/2018 | Albany | Astoria | Coos Bay | The Dalles (OR) | The Dalles (WA) | Eugene | Newport | Portland | Salem | Vancouver | Total |
|-----------|------------|------------|-----------------|-----------------|-----------------------|-------------|-------------|-------------|-------------|------------|-------------|
| November | 4,595,377 | 1,258,251 | 303,891 | 1,014,506 | 235,491 | 5,878,709 | 894,635 | 46,719,136 | 12,278,132 | 7,817,111 | 80,995,240 |
| December | 6,499,774 | 1,680,868 | 398,866 | 1,363,866 | 336,495 | 7,657,781 | 1,160,472 | 69,967,603 | 16,590,244 | 11,632,516 | 117,288,485 |
| January | 6,151,576 | 1,613,799 | 384,432 | 1,338,091 | 323,755 | 7,465,054 | 1,114,214 | 67,254,279 | 15,845,952 | 11,104,303 | 112,595,456 |
| February | 4,866,596 | 1,339,781 | 271,980 | 1,096,117 | 259,642 | 5,910,552 | 906,786 | 54,032,124 | 13,162,548 | 8,958,432 | 90,804,559 |
| March | 4,396,838 | 1,368,407 | 343,186 | 912,660 | 200,528 | 5,888,949 | 947,891 | 44,192,918 | 12,034,992 | 7,411,766 | 77,698,135 |
| April | 3,659,850 | 1,093,837 | 298,561 | 622,279 | 125,808 | 4,678,202 | 790,980 | 30,556,670 | 9,163,966 | 5,201,516 | 56,191,667 |
| May | 2,718,668 | 782,070 | 232,594 | 495,227 | 90,979 | 3,482,224 | 629,620 | 21,445,360 | 6,221,796 | 3,843,823 | 39,942,359 |
| June | 1,976,734 | 575,877 | 166,901 | 400,513 | 71,006 | 2,679,291 | 490,318 | 14,704,996 | 4,646,276 | 2,732,234 | 28,444,147 |
| July | 1,614,014 | 546,973 | 146,682 | 378,751 | 64,403 | 2,235,690 | 469,931 | 12,926,949 | 3,943,123 | 2,272,901 | 24,599,417 |
| August | 1,724,534 | 532,710 | 137,153 | 370,012 | 65,087 | 2,238,633 | 462,045 | 12,669,262 | 3,839,397 | 2,262,835 | 24,301,667 |
| September | 1,922,905 | 587,476 | 152,422 | 396,908 | 71,919 | 2,396,435 | 480,658 | 13,915,721 | 4,645,792 | 2,597,010 | 27,167,246 |
| October | 3,112,415 | 841,072 | 215,922 | 587,177 | 126,482 | 3,908,183 | 657,941 | 26,507,450 | 7,818,230 | 4,704,327 | 48,479,198 |
| Annual | 43,239,281 | 12,221,120 | 3,052,591 | 8,976,108 | 1,971,595 | 54,419,702 | 9,005,491 | 414,892,468 | 110,190,448 | 70,538,773 | 728,507,577 |
| 2016/2017 | Albany | Astoria | Coos Bay | The Dalles (OR) | The Dalles (W/Eugene) | Eugene | Newport | Portland | Salem | Vancouver | Total |
| November | 3,003,230 | 866,732 | 244,968 | 577,151 | 138,181 | 3,710,737 | 662,395 | 29,583,502 | 7,379,381 | 4,592,272 | 50,758,549 |
| December | 6,057,420 | 1,587,331 | 425,823 | 1,071,584 | 321,684 | 6,465,606 | 1,342,518 | 64,675,278 | 12,434,157 | 9,483,114 | 103,864,513 |
| January | 8,917,184 | 2,243,860 | 561,692 | 1,816,082 | 433,633 | 9,767,406 | 1,610,061 | 100,280,072 | 21,394,925 | 16,404,941 | 163,429,856 |
| February | 6,378,898 | 1,783,591 | 417,441 | 1,575,289 | 311,503 | 7,956,474 | 1,166,305 | 77,162,935 | 17,771,326 | 12,361,070 | 126,910,830 |
| March | 5,274,286 | 1,554,099 | 408,833 | 1,115,885 | 217,752 | 6,598,937 | 1,119,451 | 58,462,872 | 14,551,440 | 9,838,087 | 98,884,642 |
| April | 4,075,561 | 1,250,351 | 330,786 | 782,657 | 157,473 | 5,165,565 | 958,829 | 42,782,622 | 10,904,867 | 6,945,582 | 73,354,293 |
| May | 2,930,675 | 963,140 | 280,474 | 592,666 | 89,307 | 4,245,719 | 733,482 | 30,962,201 | 8,642,168 | 5,020,020 | 54,549,853 |
| June | 2,075,691 | 604,706 | 175,256 | 420,563 | 69,351 | 2,813,419 | 514,864 | 15,441,144 | 4,878,873 | 2,668,543 | 29,662,411 |
| July | 1,697,083 | 575,128 | 154,233 | 398,247 | 63,377 | 2,350,769 | 494,120 | 13,592,346 | 4,146,090 | 2,236,685 | 25,708,086 |
| August | 1,827,401 | 564,485 | 145,334 | 392,083 | 64,345 | 2,372,166 | 489,606 | 13,424,975 | 4,068,414 | 2,237,049 | 25,585,858 |
| September | 1,985,435 | 606,579 | 157,379 | 409,815 | 70,825 | 2,474,363 | 496,288 | 14,368,236 | 4,796,865 | 2,557,512 | 27,923,296 |
| October | 3,162,338 | 854,563 | 219,385 | 596,595 | 124,301 | 3,970,869 | 668,494 | 26,932,624 | 7,943,633 | 4,623,226 | 49,096,029 |
| Annual | 47,385,211 | 13,454,563 | 3,521,605 | 9,748,618 | 2,061,732 | 57,892,029 | 10,256,413 | 487,668,806 | 118,912,138 | 78,768,102 | 829,669,216 |
| 2015/2016 | Albany | Astoria | The Dalles (OR) | Eugene | Newport/LC | Portland | Salem | Vancouver | Total | | |
| November | 3,074,744 | 846,306 | 494,121 | 3,799,048 | 702,449 | 30,577,070 | 6,134,192 | 4,402,104 | 50,030,034 | | |
| December | 5,810,458 | 1,586,640 | 1,118,426 | 7,180,600 | 1,151,546 | 65,454,108 | 13,991,455 | 10,431,152 | 106,724,386 | | |
| January | 6,859,044 | 1,746,878 | 1,379,298 | 8,245,535 | 1,345,348 | 77,006,101 | 16,857,523 | 12,573,721 | 126,013,448 | | |
| February | 4,560,345 | 1,326,755 | 979,876 | 6,136,769 | 869,227 | 50,609,904 | 12,137,199 | 8,326,569 | 84,946,643 | | |
| March | 4,210,415 | 1,209,540 | 832,358 | 5,426,045 | 898,389 | 44,305,807 | 10,493,399 | 7,082,115 | 74,458,068 | | |
| April | 2,860,334 | 982,126 | 608,204 | 4,626,706 | 708,780 | 31,109,796 | 8,853,355 | 5,222,831 | 54,972,131 | | |
| May | 1,966,950 | 704,500 | 365,481 | 3,282,636 | 582,555 | 19,755,223 | 5,517,571 | 3,190,935 | 35,365,850 | | |
| June | 1,589,927 | 652,322 | 324,374 | 2,863,446 | 541,081 | 16,487,323 | 4,364,444 | 2,761,428 | 29,584,347 | | |
| July | 1,276,440 | 569,474 | 315,360 | 2,512,049 | 512,910 | 13,549,814 | 4,137,273 | 2,348,586 | 23,327,828 | | |
| August | 1,094,713 | 490,165 | 309,016 | 2,301,093 | 484,354 | 11,915,029 | 3,596,497 | 2,087,015 | 20,500,124 | | |
| September | 1,290,982 | 519,961 | 308,947 | 2,343,325 | 535,853 | 13,080,874 | 3,890,952 | 2,248,661 | 24,739,046 | | |
| October | 2,058,103 | 655,682 | 400,183 | 2,906,804 | 633,634 | 20,461,984 | 5,354,997 | 3,227,248 | 51,989,926 | | |
| Annual | 36,652,454 | 11,290,349 | 7,435,643 | 51,624,055 | 8,966,126 | 394,313,032 | 95,328,857 | 63,902,363 | 685,201,829 | | |
| 2014/2015 | Albany | Astoria | The Dalles (OR) | Eugene | Newport/LC | Portland | Salem | Vancouver | Total | | |
| November | 3,490,958 | 869,406 | 739,467 | 4,017,243 | 761,672 | 33,112,773 | 6,228,375 | 4,808,471 | 54,028,365 | | |
| December | 5,847,879 | 1,367,602 | 1,245,731 | 6,776,032 | 921,294 | 59,955,127 | 13,259,278 | 9,648,654 | 99,021,398 | | |
| January | 6,351,751 | 1,511,674 | 1,385,617 | 7,384,910 | 1,127,141 | 65,692,741 | 14,491,558 | 10,585,680 | 108,531,072 | | |
| February | 4,503,610 | 1,122,974 | 1,087,328 | 5,805,289 | 768,470 | 47,086,991 | 11,421,381 | 7,829,682 | 79,624,824 | | |
| March | 4,158,320 | 1,121,188 | 913,284 | 5,503,855 | 806,489 | 38,235,877 | 9,848,434 | 6,201,912 | 66,189,358 | | |
| April | 3,717,325 | 981,132 | 727,827 | 4,717,038 | 774,036 | 32,236,045 | 8,249,792 | 5,074,817 | 56,478,012 | | |
| May | 2,664,122 | 782,272 | 580,411 | 3,898,397 | 634,775 | 23,625,974 | 6,697,473 | 3,789,305 | 42,672,730 | | |
| June | 1,840,466 | 647,219 | 429,546 | 2,824,482 | 551,338 | 15,117,689 | 4,430,159 | 2,542,401 | 28,383,298 | | |
| July | 1,432,574 | 550,017 | 382,927 | 2,328,798 | 491,887 | 11,488,733 | 3,356,047 | 1,895,492 | 21,926,476 | | |
| August | 1,479,412 | 496,116 | 392,405 | 2,151,660 | 453,438 | 10,679,209 | 3,115,291 | 1,785,762 | 20,553,293 | | |
| September | 1,731,118 | 511,828 | 426,199 | 2,268,709 | 504,023 | 12,315,742 | 3,477,020 | 2,079,370 | 23,314,009 | | |
| October | 2,061,765 | 577,540 | 473,559 | 2,809,490 | 492,610 | 15,383,719 | 4,344,711 | 2,494,906 | 28,638,300 | | |
| Annual | 39,279,100 | 10,538,968 | 8,784,299 | 50,485,903 | 8,287,172 | 364,929,719 | 88,919,520 | 58,736,452 | 629,961,134 | | |
| 2013/2014 | Albany | Astoria | The Dalles (OR) | Eugene | Newport/LC | Portland | Salem | Vancouver | Total | | |
| November | 3,004,316 | 923,615 | 752,502 | 4,951,166 | 773,173 | 35,213,397 | 8,421,835 | 5,303,793 | 59,343,797 | | |
| December | 7,773,336 | 1,773,068 | 1,371,882 | 8,478,833 | 1,393,910 | 73,290,876 | 15,193,898 | 11,654,376 | 120,930,179 | | |
| January | 7,314,992 | 1,764,673 | 1,520,332 | 9,839,902 | 1,249,414 | 67,670,980 | 19,041,102 | 12,893,003 | 131,294,398 | | |
| February | 6,676,619 | 1,663,860 | 1,442,076 | 7,936,329 | 1,120,325 | 72,081,981 | 15,896,859 | 11,761,142 | 118,579,191 | | |
| March | 4,458,858 | 1,237,372 | 1,159,727 | 5,962,629 | 864,287 | 51,903,144 | 12,484,347 | 8,469,900 | 86,540,264 | | |
| April | 3,776,291 | 1,049,610 | 784,535 | 5,052,348 | 779,630 | 36,250,554 | 9,500,909 | 5,960,021 | 63,153,898 | | |
| May | 2,855,731 | 770,344 | 612,151 | 3,922,913 | 584,808 | 24,906,632 | 6,850,569 | 4,016,235 | 44,519,383 | | |
| June | 1,904,412 | 586,081 | 470,687 | 3,016,935 | 517,593 | 16,685,126 | 4,754,490 | 2,725,858 | 30,661,182 | | |
| July | 1,597,377 | 562,799 | 415,682 | 2,491,542 | 502,615 | 13,198,442 | 3,914,695 | 2,234,904 | 24,918,056 | | |
| August | 1,511,671 | 530,842 | 380,067 | 2,240,954 | 468,602 | 10,815,694 | 3,171,714 | 1,812,836 | 20,932,379 | | |
| September | 1,637,412 | 510,399 | 390,868 | 2,220,473 | 483,630 | 11,242,660 | 3,430,400 | 1,899,175 | 21,815,016 | | |
| October | 1,980,952 | 517,141 | 420,442 | 2,571,228 | 459,522 | 13,984,555 | 3,967,612 | 2,228,583 | 26,130,034 | | |
| Annual | 44,491,967 | 11,889,804 | 9,720,950 | 58,685,251 | 9,197,509 | 437,244,041 | 106,628,429 | 70,959,826 | 748,817,777 | | |
| 2012/2013 | Albany | Astoria | The Dalles (OR) | Eugene | Newport/LC | Portland | Salem | Vancouver | Total | | |
| November | 3,980,097 | 983,796 | 694,036 | 4,029,196 | 790,299 | 32,332,665 | 7,420,633 | 5,068,731 | 55,299,453 | | |
| December | 5,425,390 | 1,368,991 | 1,023,998 | 6,374,613 | 1,082,073 | 55,049,568 | 11,982,401 | 8,655,000 | 82,526,033 | | |
| January | 7,623,154 | 1,794,161 | 1,547,874 | 8,535,059 | 1,485,395 | 80,560,285 | 17,009,938 | 12,874,734 | 131,430,600 | | |
| February | 6,143,084 | 1,592,883 | 1,247,819 | 7,750,244 | 1,059,617 | 63,211,648 | 15,987,682 | 10,413,124 | 107,406,100 | | |
| March | 4,823,792 | 1,349,940 | 1,002,932 | 6,319,169 | 1,035,028 | 49,517,478 | 12,577,871 | 8,201,439 | 84,827,650 | | |
| April | 3,629,993 | 1,071,117 | 855,673 | 4,976,097 | 843,776 | 36,067,438 | 9,392,593 | 5,920,050 | 62,756,736 | | |
| May | 1,857,990 | 805,939 | 560,211 | 3,370,006 | 579,423 | 23,346,350 | 6,872,771 | 4,031,753 | 41,424,443 | | |
| June | 2,560,019 | 697,834 | 508,908 | 3,181,901 | 611,895 | 19,329,442 | 5,292,184 | 3,189,278 | 35,371,462 | | |
| July | 1,219,385 | 541,620 | 412,307 | 2,382,000 | 534,531 | 13,262,177 | 3,717,540 | 2,323,146 | 24,392,706 | | |
| August | 1,826,950 | 544,793 | 367,119 | 2,229,168 | 527,684 | 12,014,710 | 3,731,707 | 2,079,382 | 23,321,513 | | |
| September | 1,562,984 | 514,216 | 383,906 | 2,422,690 | 473,131 | 12,267,612 | 3,721,567 | 2,089,454 | 23,435,560 | | |
| October | 3,810,945 | 717,439 | 615,143 | 3,575,465 | 707,577 | 23,151,713 | 6,242,844 | 3,839,276 | 42,660,402 | | |
| Annual | 44,463,783 | 11,982,727 | 9,219,927 | 55,145,608 | 9,730,428 | 420,111,086 | 103,949,731 | 68,685,367 | 723,288,657 | | |

Section V.4 - Market Information

General historical and forecasted (one year ahead) conditions in the national and regional physical and financial natural gas purchase markets. This should include descriptions of each major supply point from which the LDC physically purchases and the major factors affecting supply, prices, and liquidity at those points.

Deregulation from the late 1970s to early 1990s was a response to perceived natural gas shortages. In the new unregulated environment, prices dropped due to competition, increased efficiencies, technological improvements, and the discovery of more natural gas.

In the early 2000s, prices rose dramatically due to tightness in the supply/demand balance, a situation that Enron (and others) sought to exploit. This led to scandals, lawsuits, regulatory investigations, bankruptcies and other headline-making news that obscured the fact that gas supplies really were tightening and that demand growth would be dependent on bringing additional supplies to North America in the form of LNG imports. Catastrophic hurricanes (Katrina, Rita, et al) in 2005 interrupted natural gas supplies from the Gulf of Mexico and prices spiked again. Gas prices soared in the spring and summer of 2008 on the tails of predicted supply shortfalls. At that time, Henry Hub prices peaked at \$13.31/Dth. Within months, the onset of a global economic recession reduced demand while the advent of horizontal drilling into shale formations unleashed a surge of production. Prices soon tumbled (Figure 1). Historical indexed prices into the Pacific Northwest at NW Natural's major supply points reflected national trends (Figure 2).

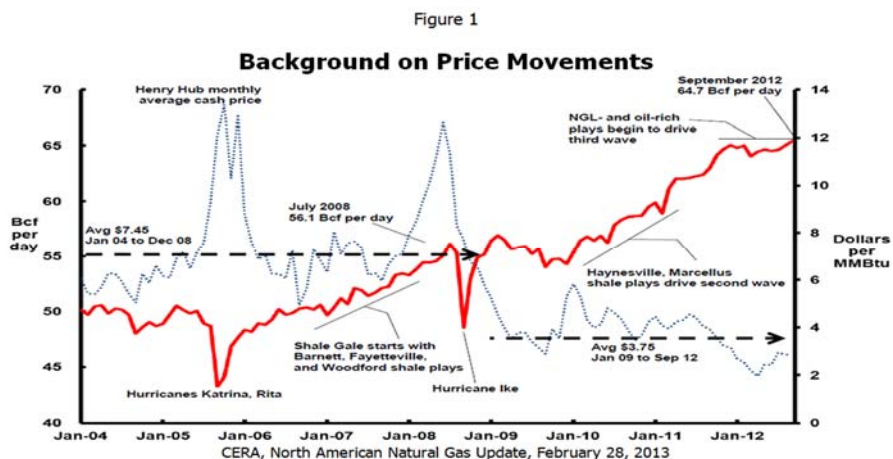
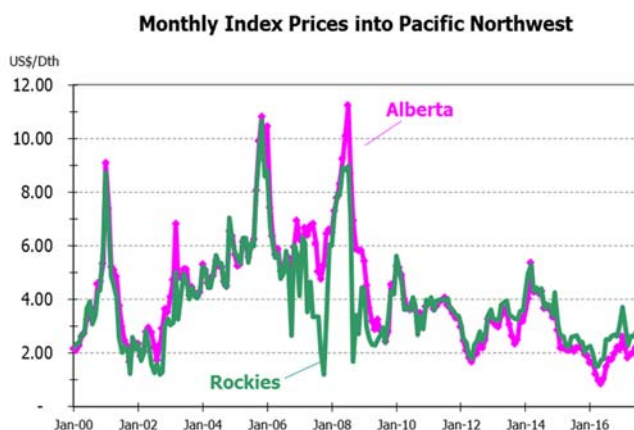


Figure 2

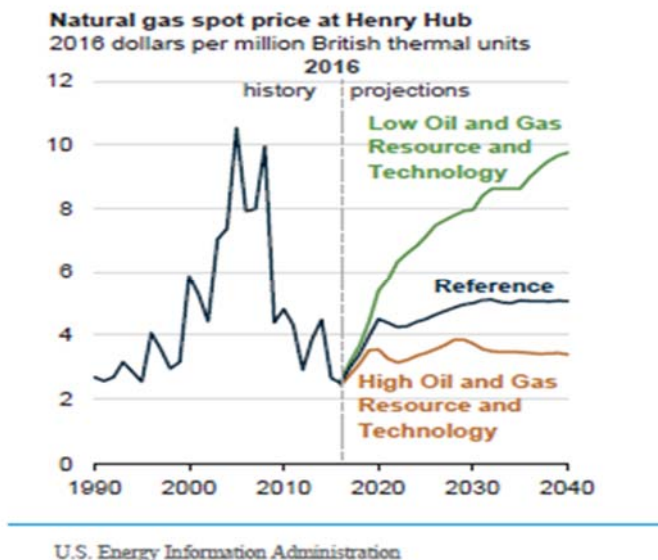


As mentioned, production began ramping up in 2008 with the surge in shale drilling innovations. Prices fell dramatically, and as shown in Figure 2, bottomed out in spring 2012. Prices then rose and fell again, aided primarily

by the weather. First there was the so-called "Polar Vortex" that swept the eastern half of the country in 2013/14 and again in 2014/15, then the exceedingly warm El Niño winter of 2015/2016.

The U.S. Energy Information Administration's (EIA) 2017 Annual Energy Outlook (AEO) has a reference case price forecast, as well as high and low cases that reflect the potential impact of new technologies. EIA expects prices to rise the new few years from today's low levels. Thereafter, price movements become increasing dependent on the pace of technological innovation. The EIA price forecast for the Henry Hub in 2016\$ is shown in Figure 3.

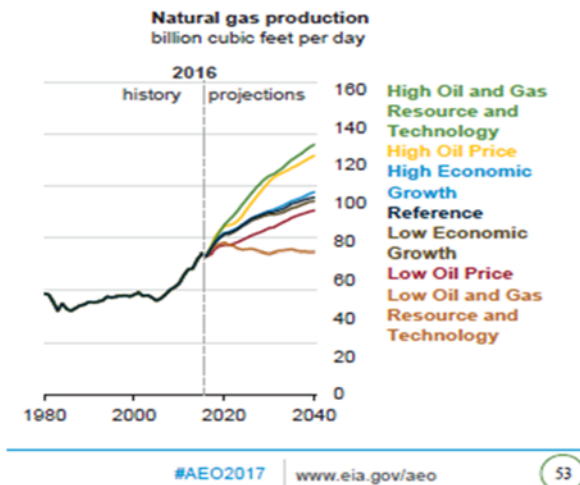
Figure 3



Some of the major factors affecting this outlook are:

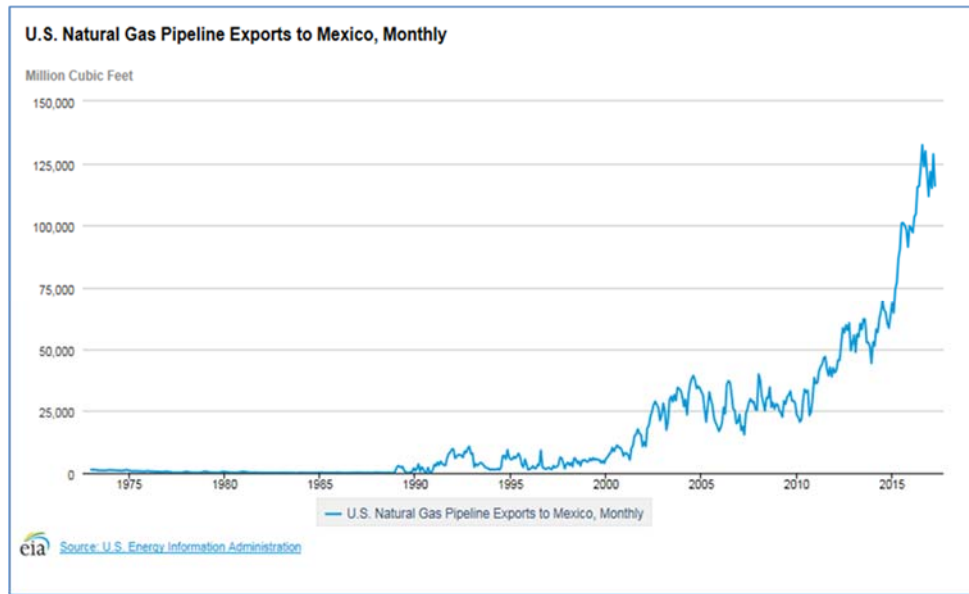
1. In its 2017 AEO, EIA forecasts that natural gas production will continue to grow quickly under most scenarios (see Figure 4). However, in its *Natural Gas Monthly* published on June 30, 2017, EIA reported that April 2017 marked the 14th consecutive month in which natural gas production decreased from the same year a year earlier.

Figure 4



2. Gas exports will continue to grow. While LNG export terminals rightfully gather major headlines, the increase of exports via pipeline to Mexico goes largely unnoticed. In reality, gas exports to Mexico will soon approach an amount equivalent to one 3 Bcf LNG tanker load every day (see Figure 5).

Figure 5

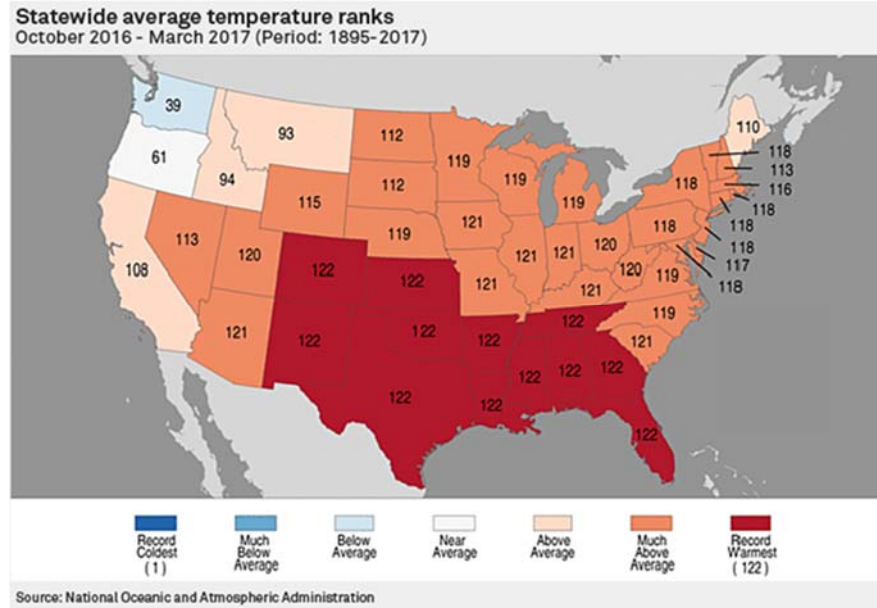


3. Deviations from "Normal" Conditions. Temperatures, hydro levels and storage inventories are examples of factors that can have large short-term effects, but when looking a year or more into the future, are normalized to some extent in price forecasts. This means variations in any of these factors from normal or expected conditions will increase price volatility if not outright price levels. For example, the 2013-2014 winter was probably when many people first started hearing the term "Polar Vortex," and the extremely cold temperatures drained storage inventories down to levels that had not been seen in over a decade. The "hangover" from that winter continued through the following year because it affected both the cost to refill storage during summer 2014 as well as influence 2014-2015 winter prices. Then came the exceedingly warm winter of 2015/2016, which ranks as the #1 hottest winter (October-March) in the 122 years that the National Oceanic and Atmospheric Administration (NOAA) has tracked temperatures. Not too surprisingly, storage inventory levels across the country reached a record high in November 2016. And then warm weather struck again with the winter of 2016/2017 rated #2 by NOAA in terms of warmth over the last 122 years.

Figure 5 shows the temperature pattern of last winter on a state-by-state basis. Only Oregon and Washington experienced anything close to cooler or colder than normal weather, but our gas demand is not nearly large enough to sway continental natural gas prices.

It is unlikely that the warmth of the last two winters will repeat again this year, so temperature-related demand is also certain to be higher this coming winter, which would put upward pressure on natural gas prices.

Figure 6



Regarding liquidity at our major supply points in the Rockies and western Canada, it is likely to continue to be very strong for the next couple of years. That is, Rockies and western Canadian gas that typically flowed to mid-Continent and east coast markets will continue to be displaced by the growth in gas supplies from eastern shale plays such as Marcellus. It is likely, though, that demand growth - some combination of power gen, industrial loads and regional LNG exports - will catch up with available supplies, spurring a strong price response. The magnitude of the price response will depend on the ability of gas producers to tap more supplies from western Canada (B.C. shales) and the Rockies.

Section V.5 - Data Interpretation

If not included in the PGA filing please explain the major aspects of the LDC's analysis and interpretation of the data and information described in (1) and (2) above, the most important conclusions resulting from that analysis and interpretation, and the application of these conclusions in the development of the current PGA portfolio.

See Exhibit C, IV.2.b

Section V.6 - Credit Worthiness Standards

A copy of the Board or officer approved credit worthiness standards in place for the period in which the current gas supply portfolio was developed, along with full documentation for these standards. Also, a copy of the credit worthiness standards actually applied in the purchase of physical gas and entering into financial hedges. If the two are one and the same, please indicate so.

IV. Credit Risk Management

The following steps are taken by the Front, Mid and Back Offices to provide credit risk management:

| | Procedure | Responsible Office |
|----|---|----------------------------|
| 1 | Analyzes the counterparty's profile to determine credit risk tolerances. | Mid Office |
| 2 | Sets counterparty credit limits in accordance with company policy (see Exhibit "E" of the Gas Supply Risk Management Policies). | Mid Office |
| 3 | Monitors credit exposure and coordinates with the Front Office to mitigate risk. | Mid Office |
| 4 | If the credit exposure amount exceeds the counterparty credit limit, verifies the limit violation. | Mid Office |
| 5 | Notifies Front Office Executive of limit violations in physical transactions, and Mid Office Executive of limit violations in financial transactions. | Mid Office |
| 6 | Determines any appropriate action in response to physical transaction violations. | Front Office Executive |
| 7 | Communicates instructions for dealing with physical transaction violations to Front Office and submits copies of the instructions to the Mid Office. | Front Office Executive |
| 8 | Determines any appropriate action in response to financial transaction violations that are not already addressed in the Derivatives Policy. | Mid Office Executive |
| 9 | Communicates instructions for dealing with financial transaction violations to Front Office and submits copies of the instructions to the Mid Office. | Mid Office Executive |
| 10 | Calculates and analyzes various credit risk metrics to better understand the current and potential risks in the portfolio. | Mid Office |
| 11 | Calculates and records appropriate credit reserves on a monthly basis. | Mid Office |
| 12 | Reviews credit limits at least twice a year, and additionally as needed, to assess whether changes should be made. | Mid Office |
| 13 | Monitors news articles, bankruptcy filings, legal actions, etc. on a daily basis for all established counterparties. | Front Office Mid Office |

Source: NW Natural General Procedure G-72; Physical and financial Commodity Transaction Procedures Effective March 28, 2005; Last updated January 5, 2015

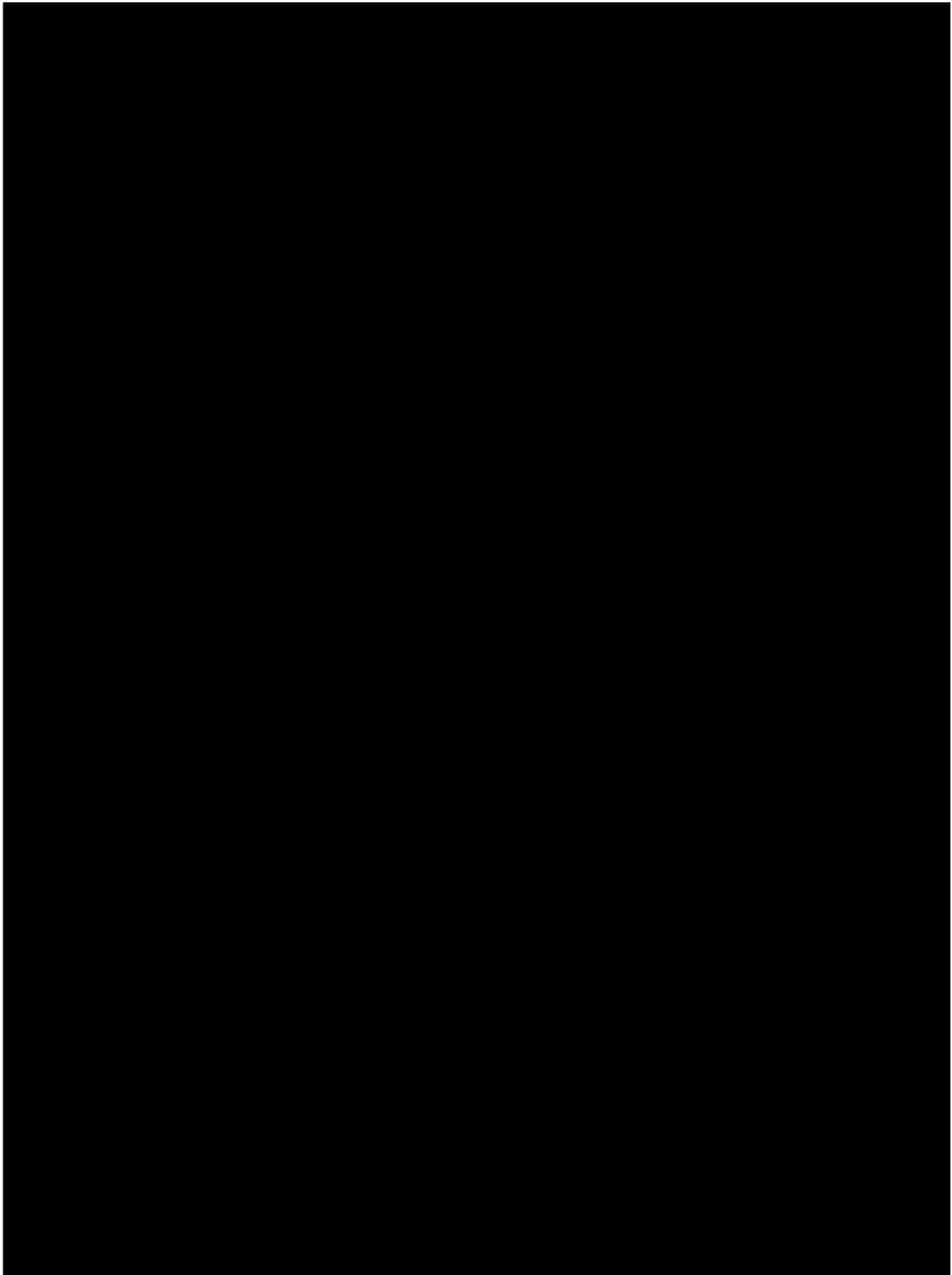
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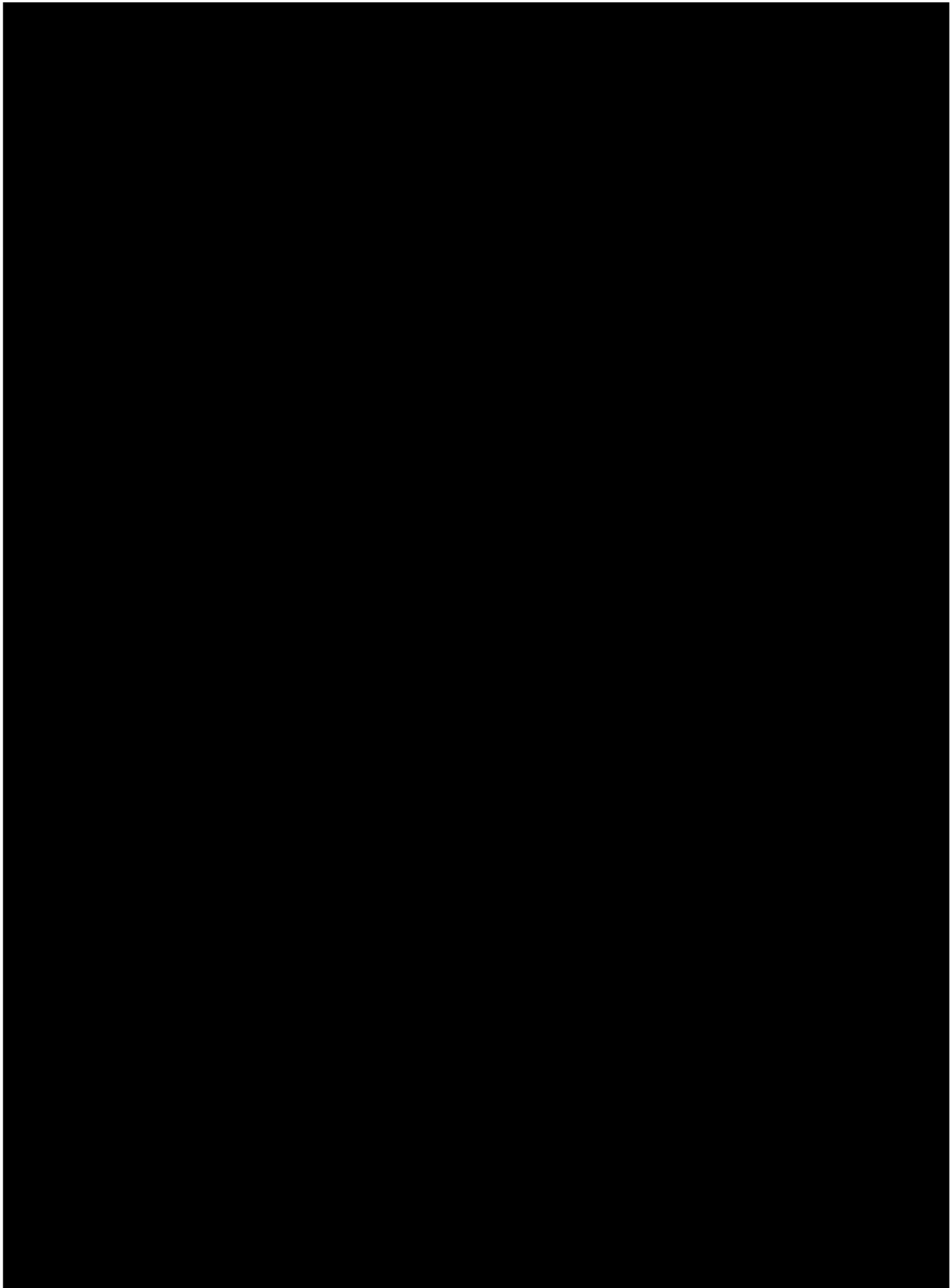
Gas Supply Risk Management Policies

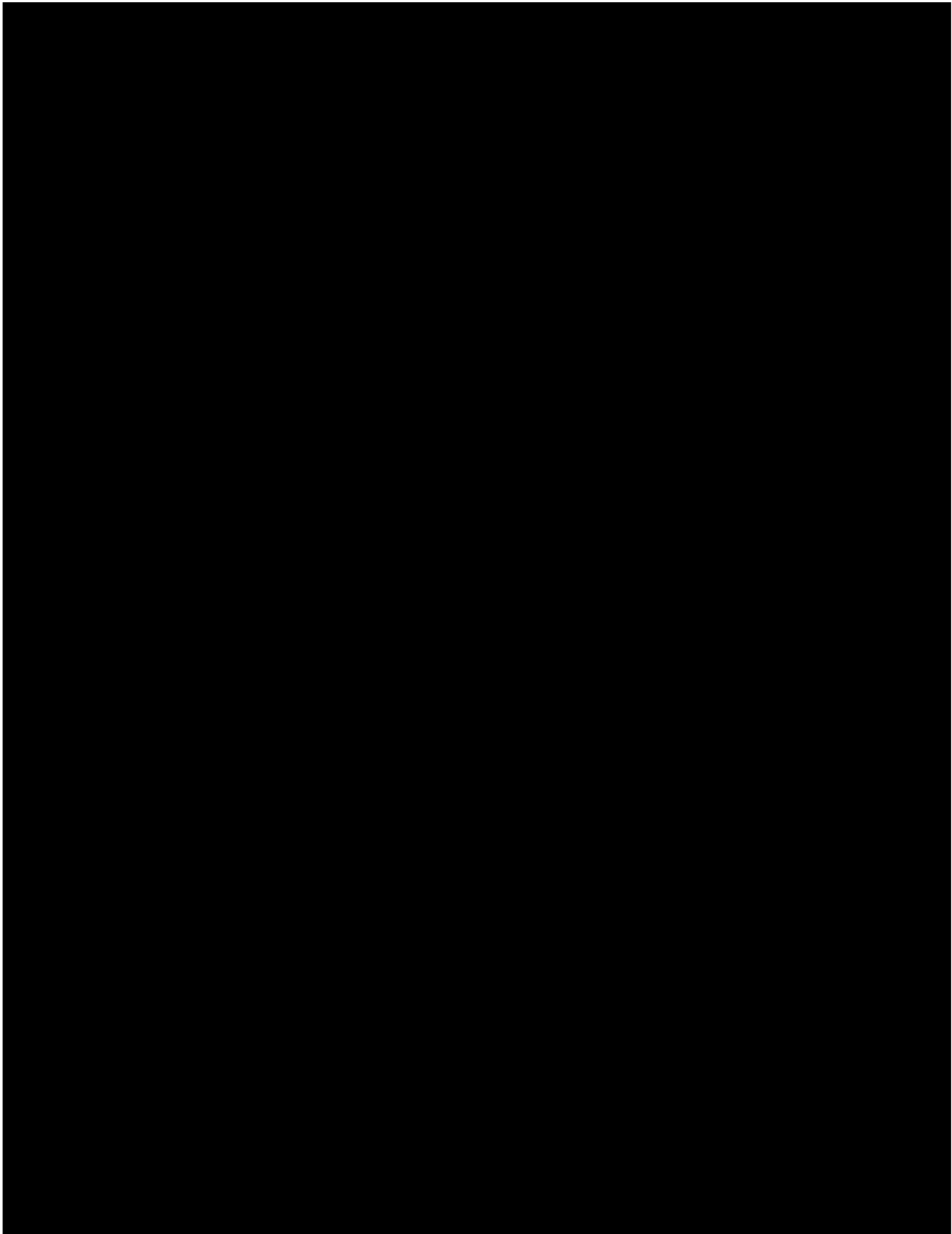
Index No. 110

September 22, 2016

Original Date of Approval: March 29, 2005

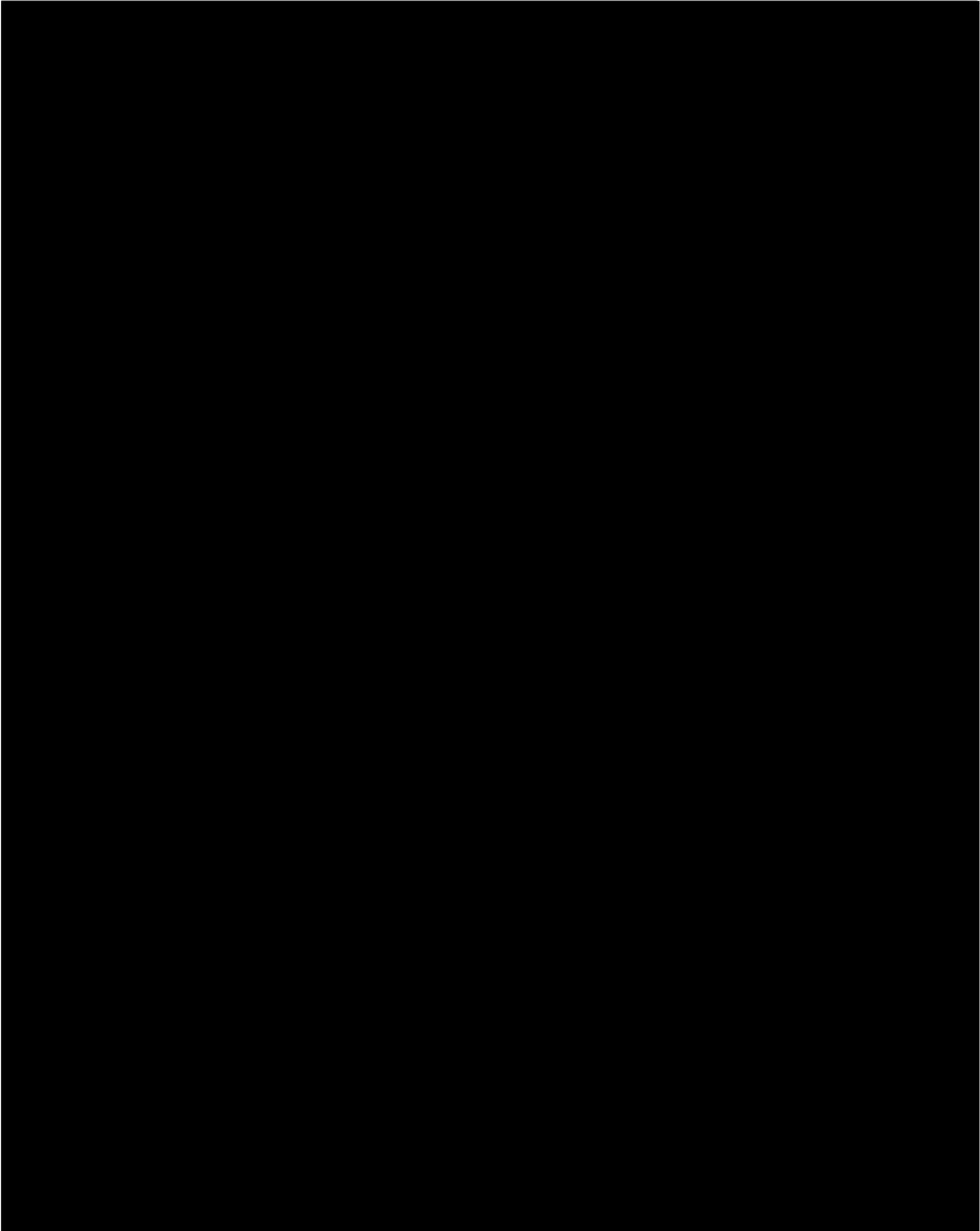


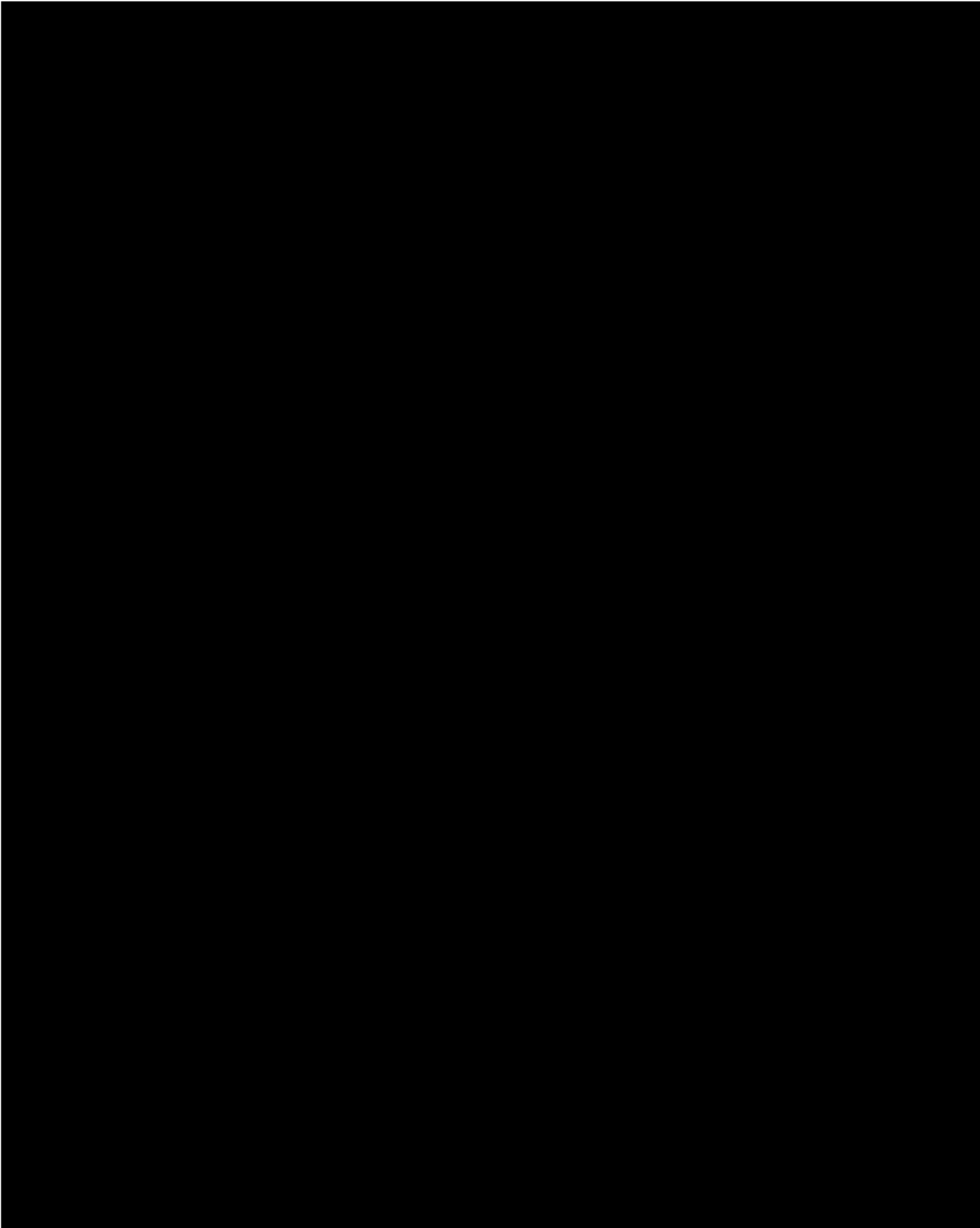


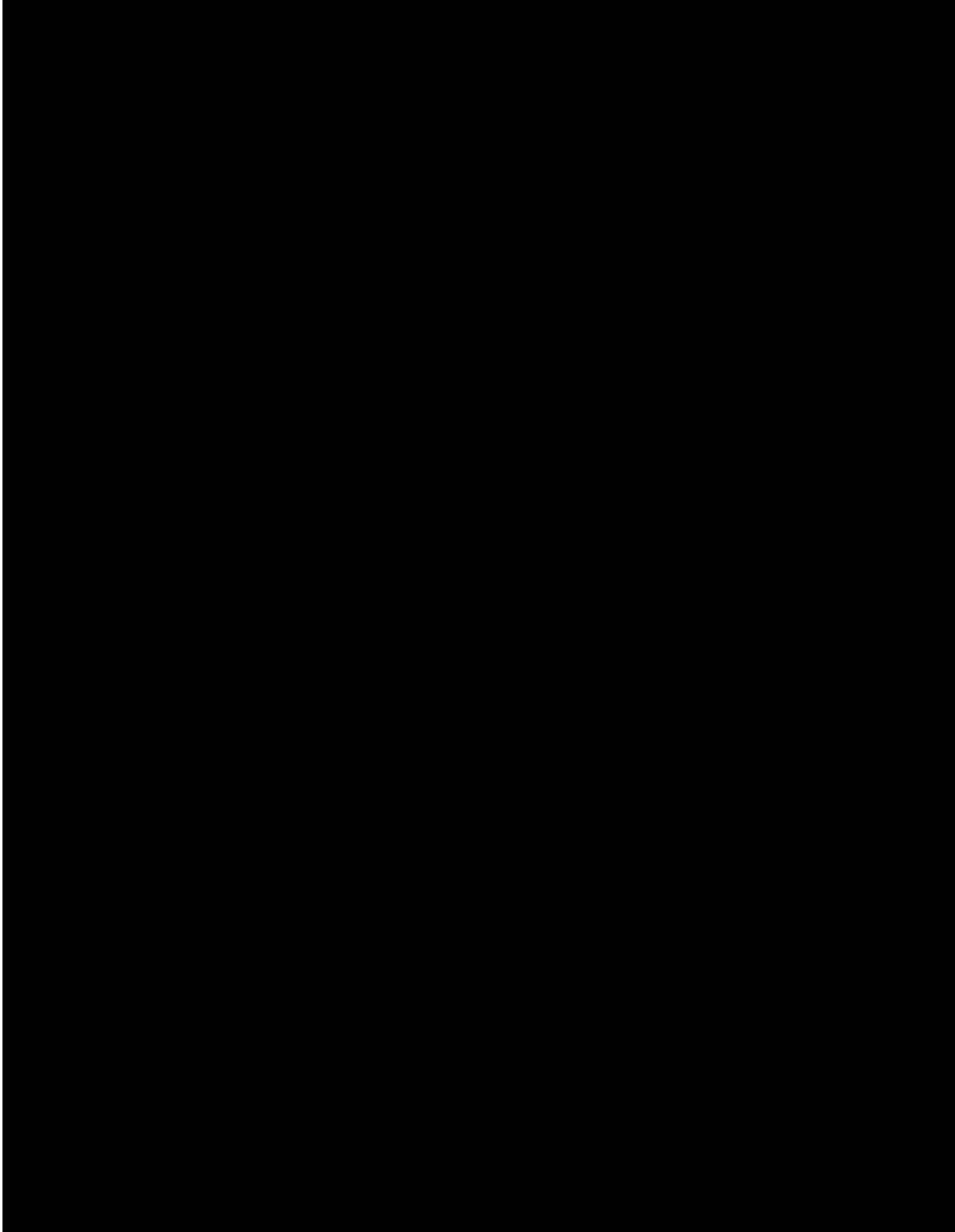


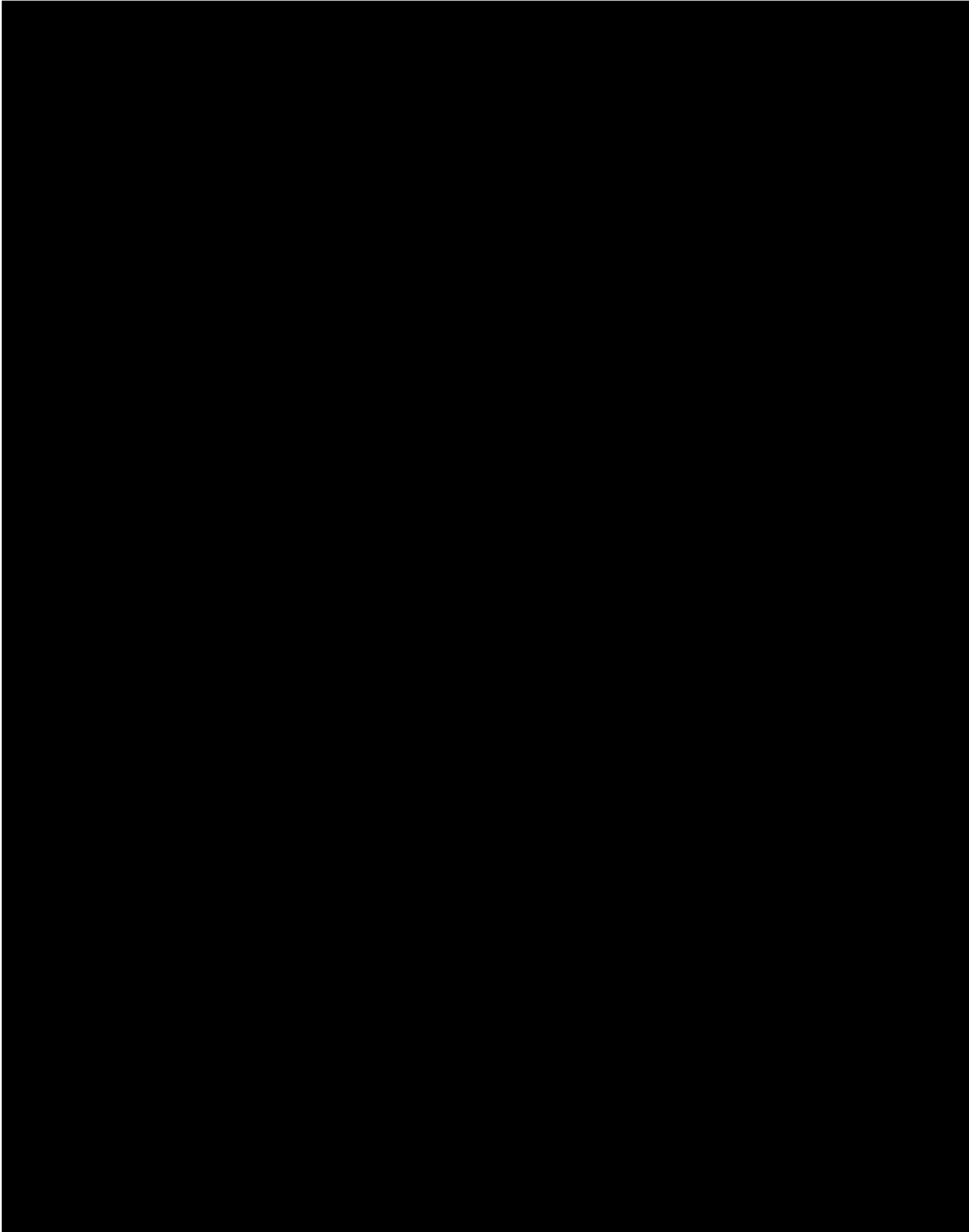
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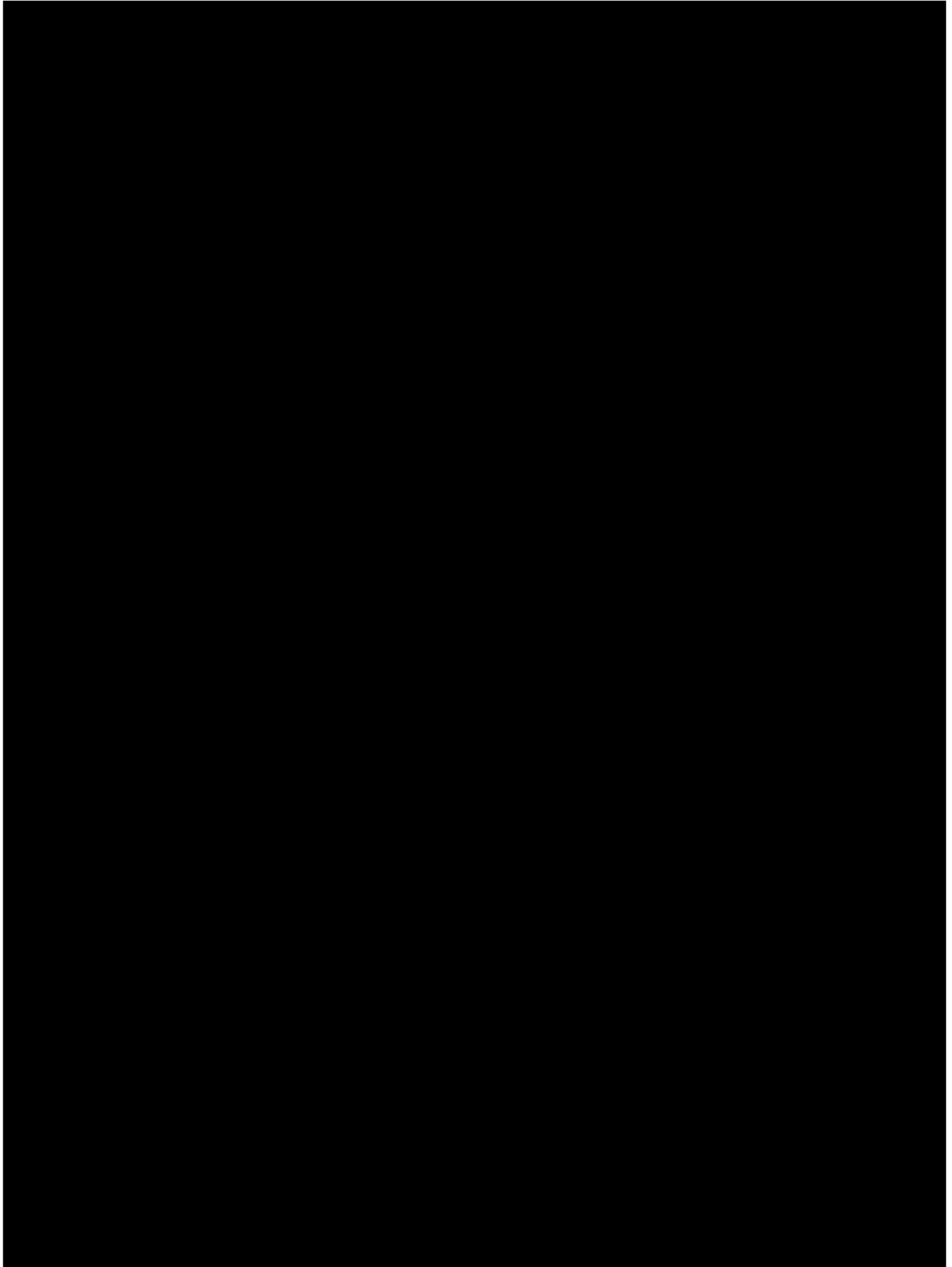
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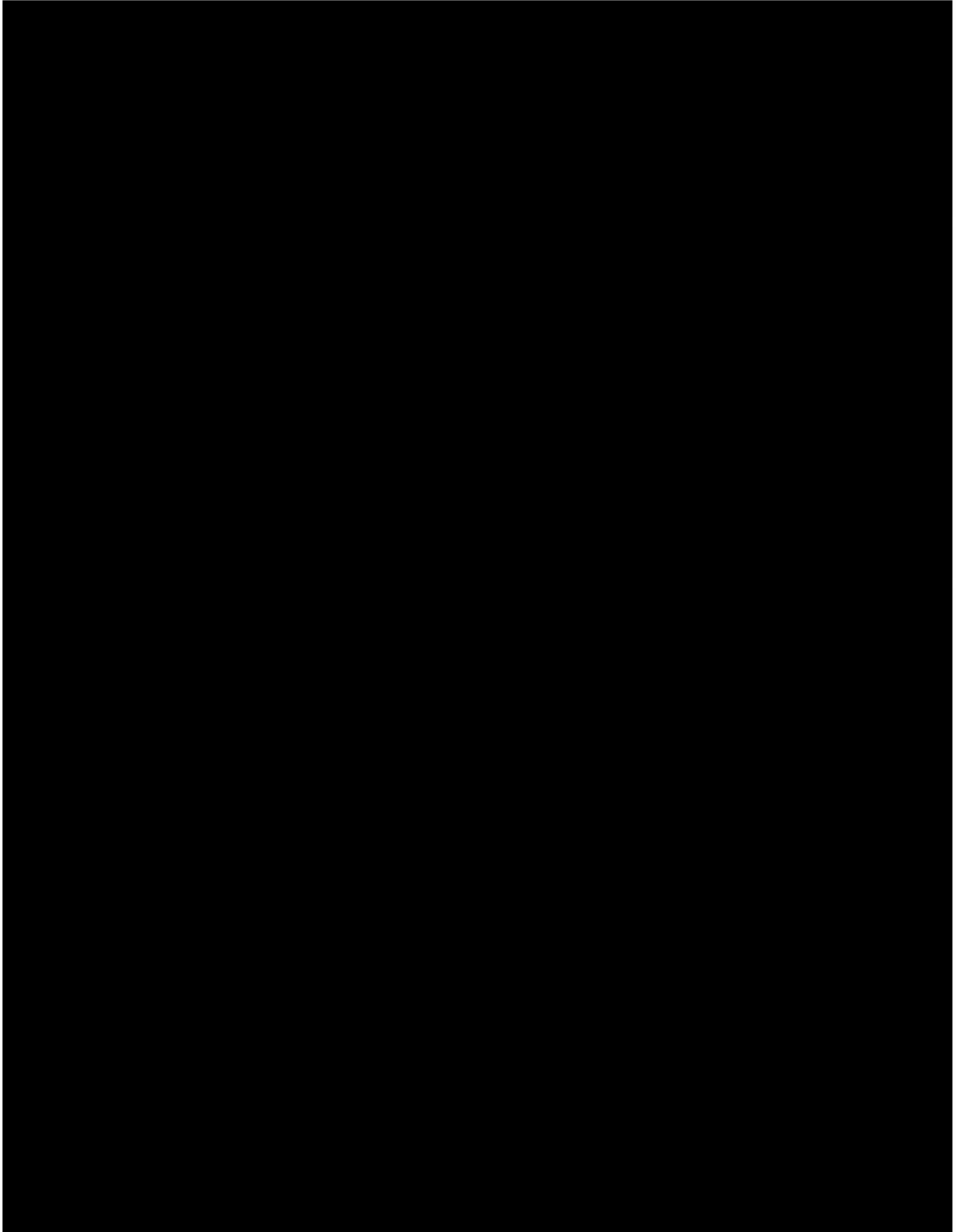


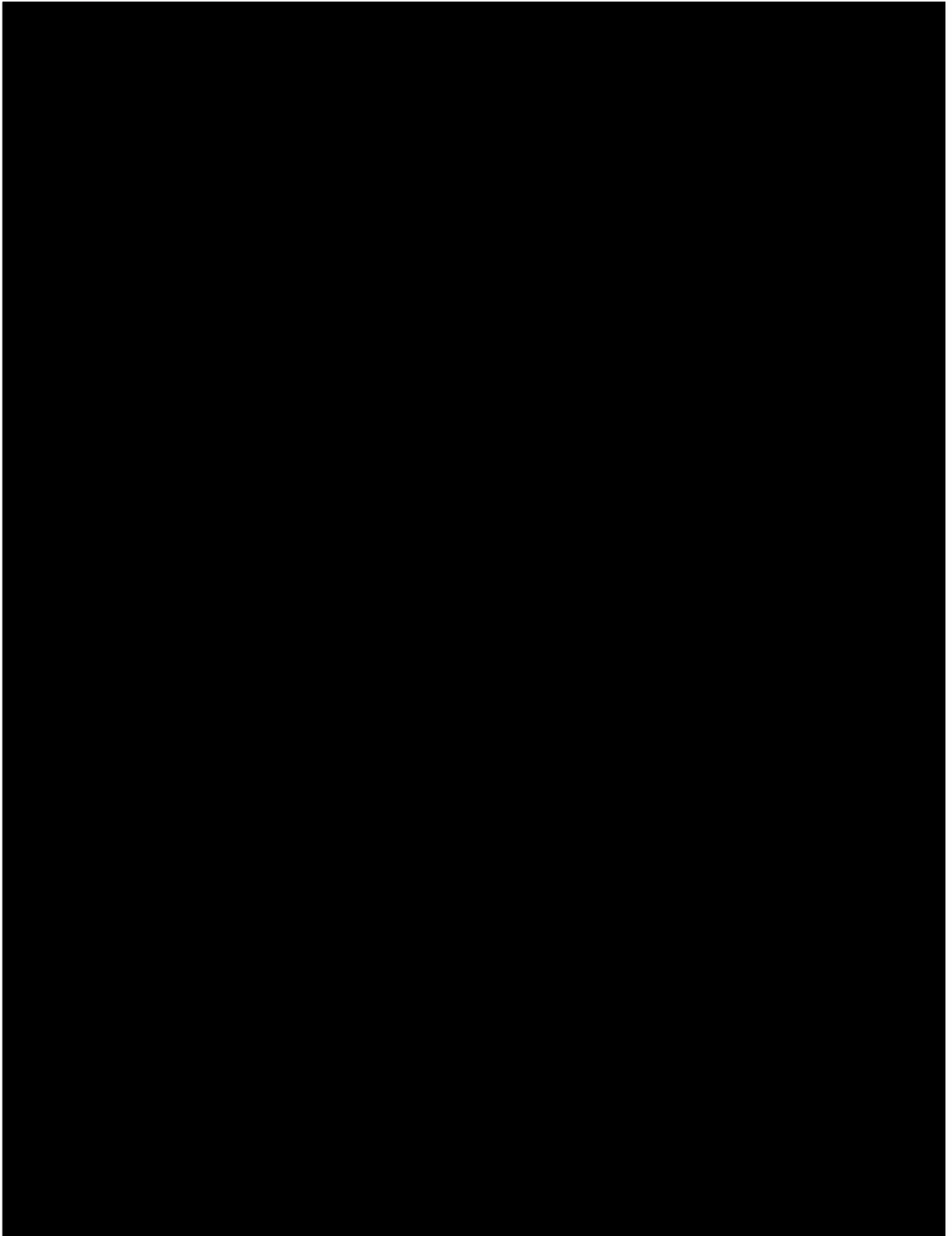


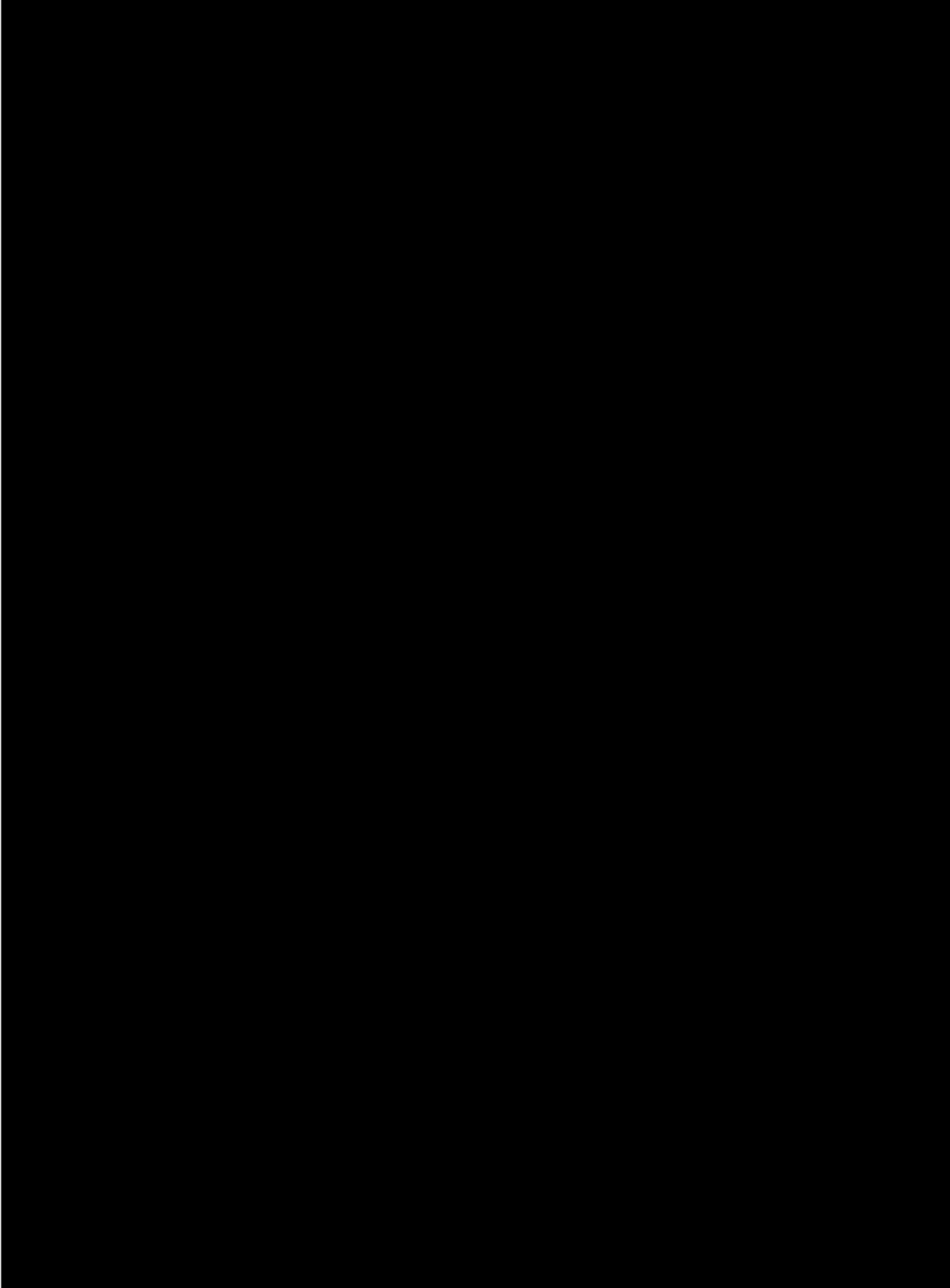
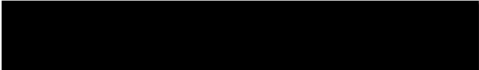


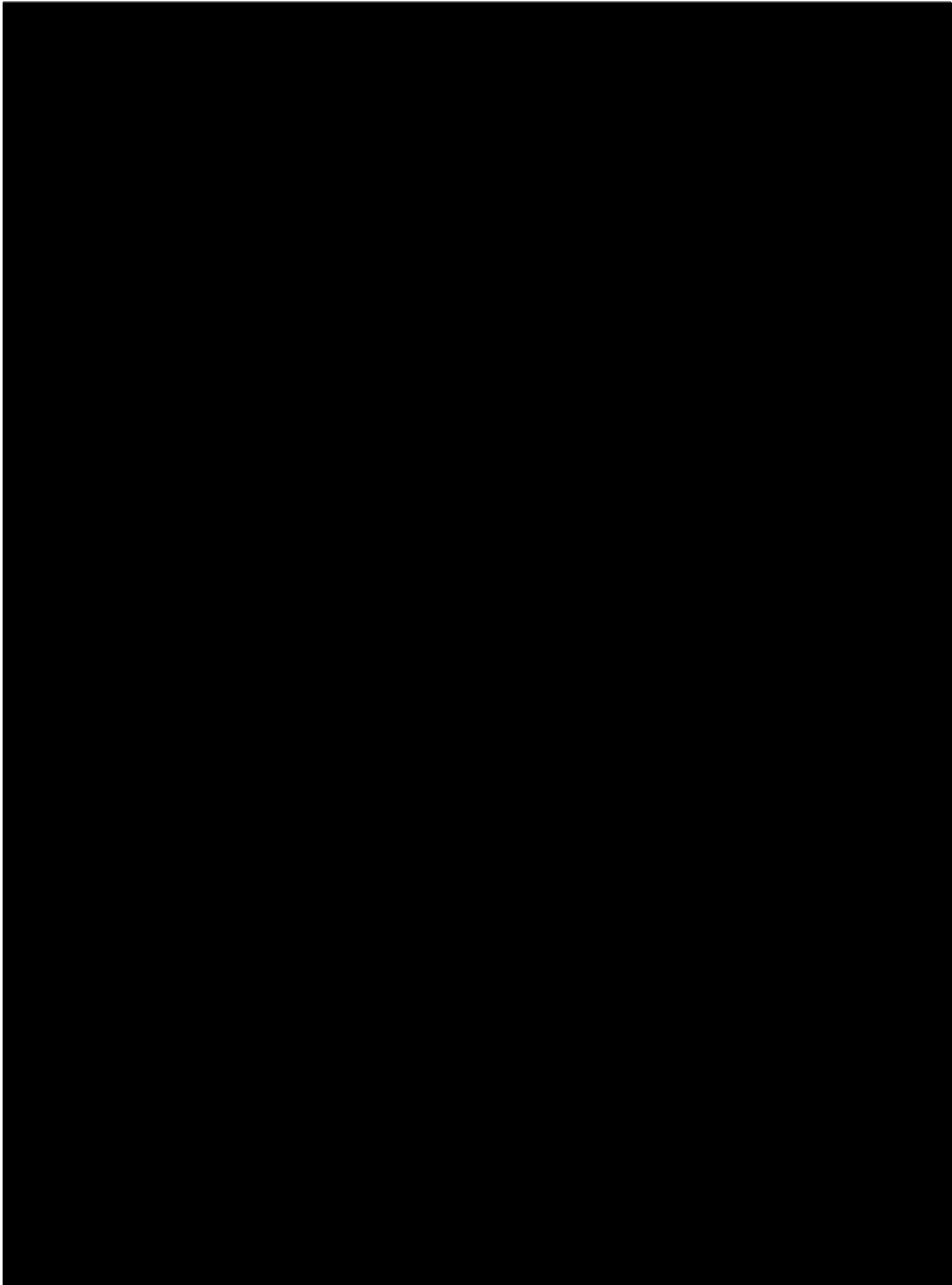
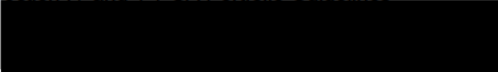


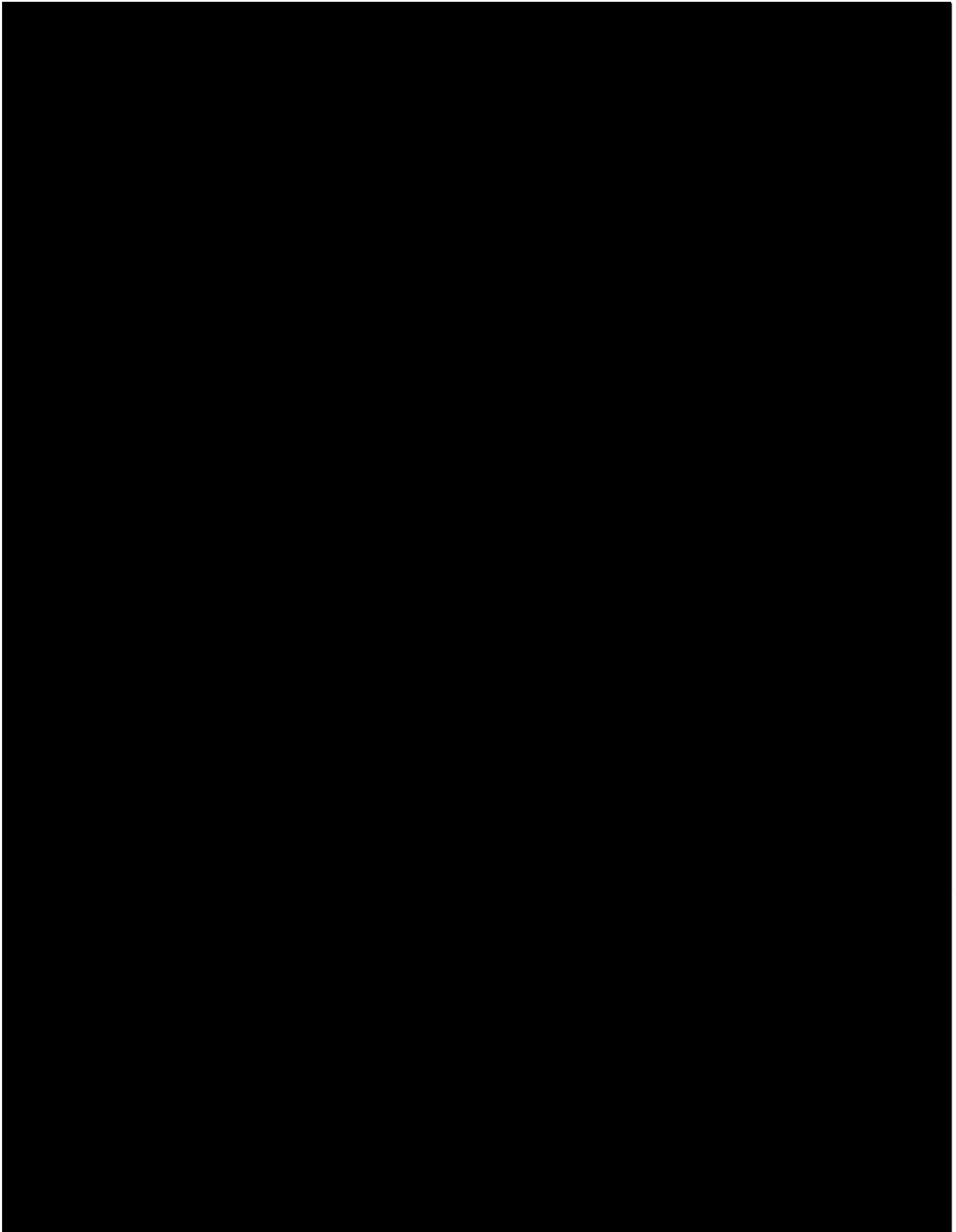
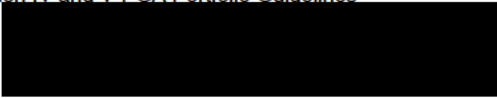


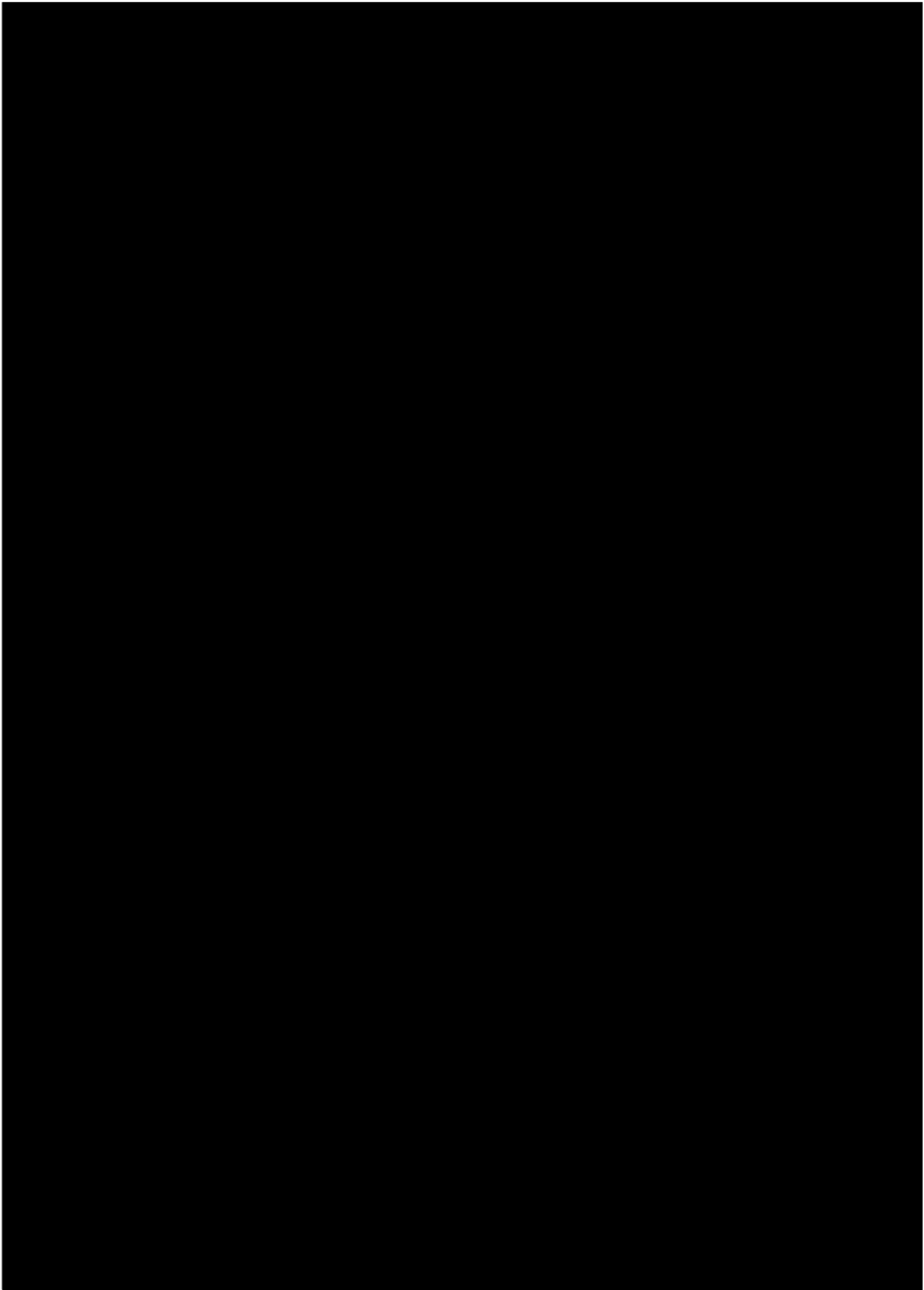


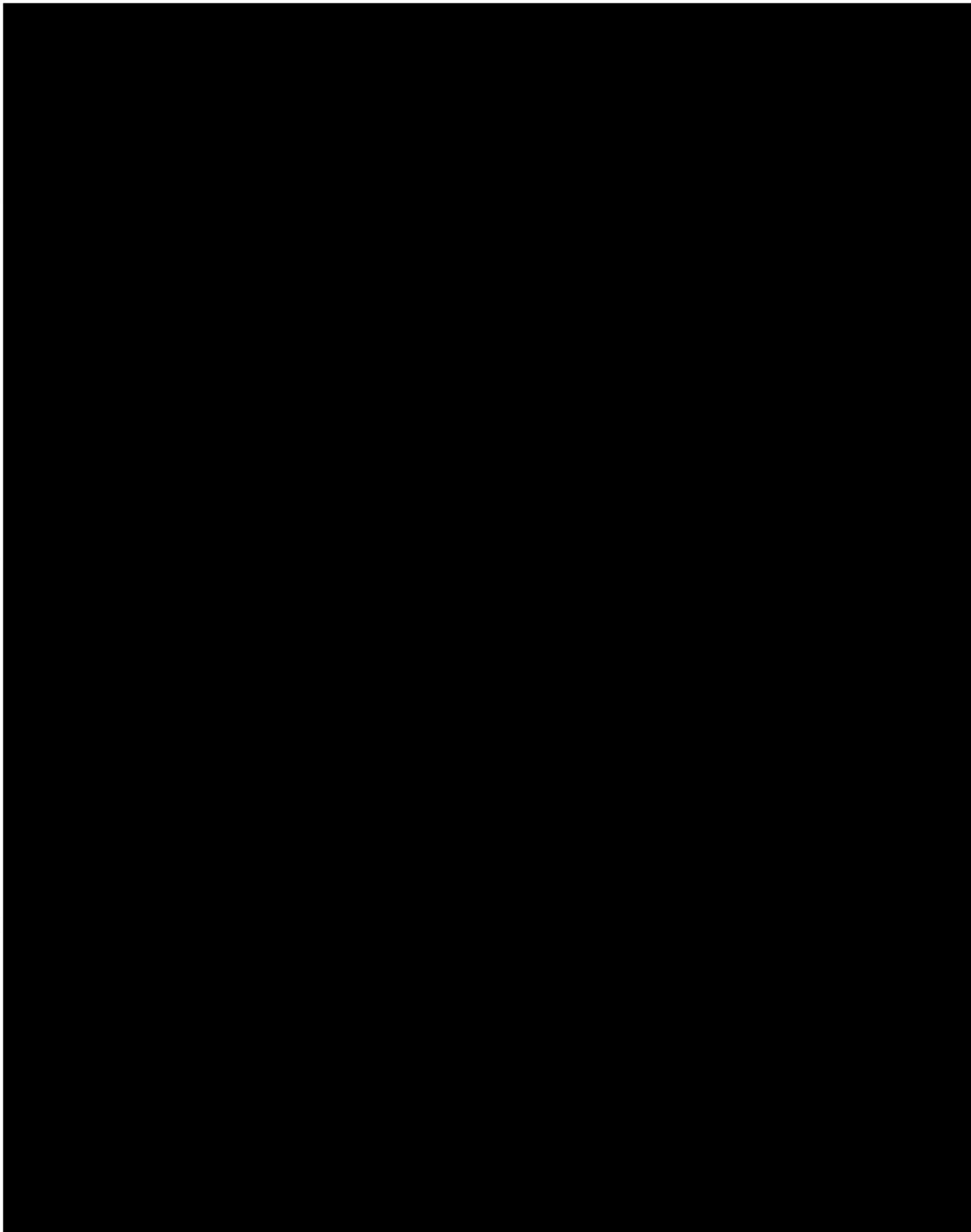


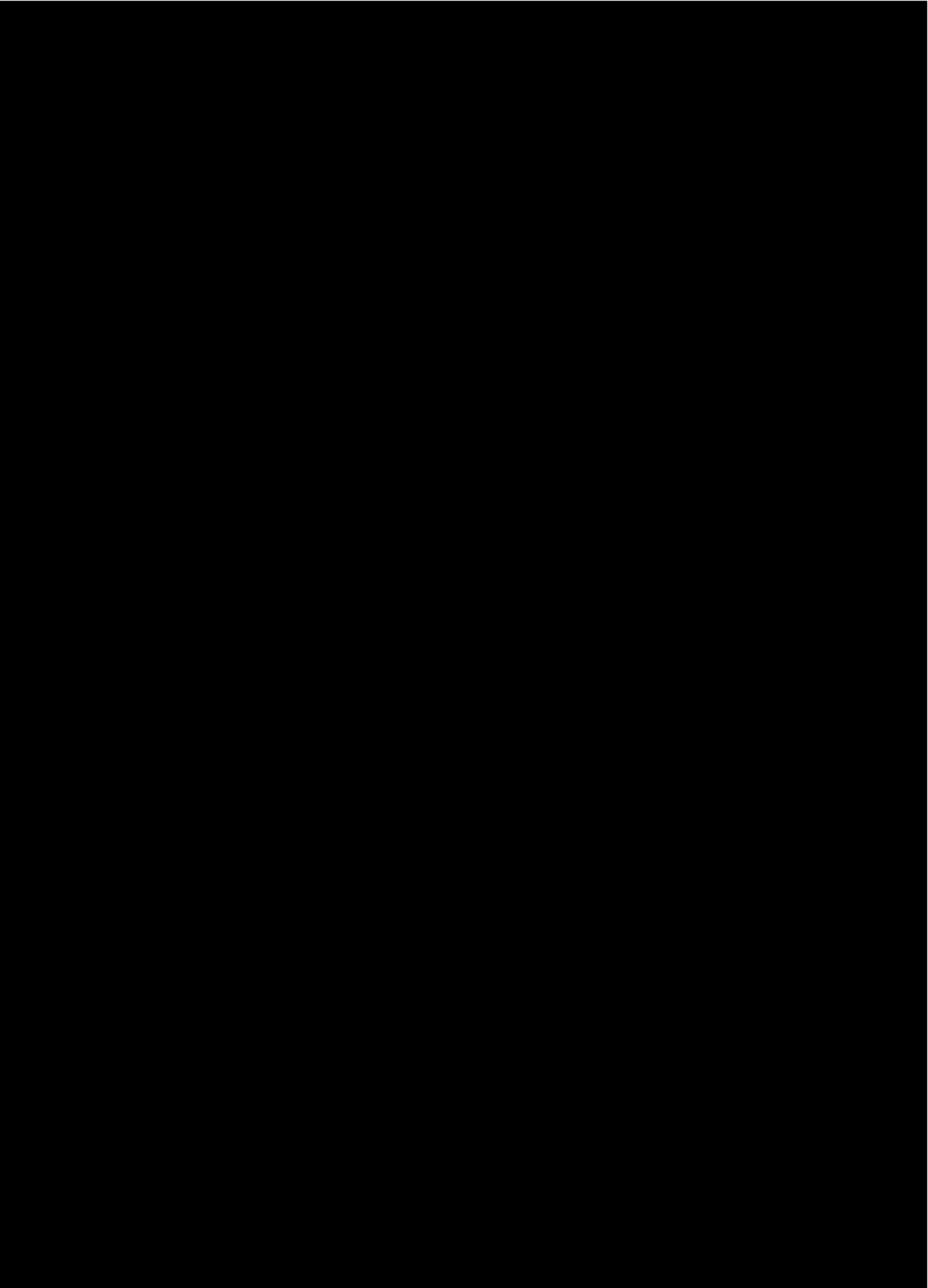


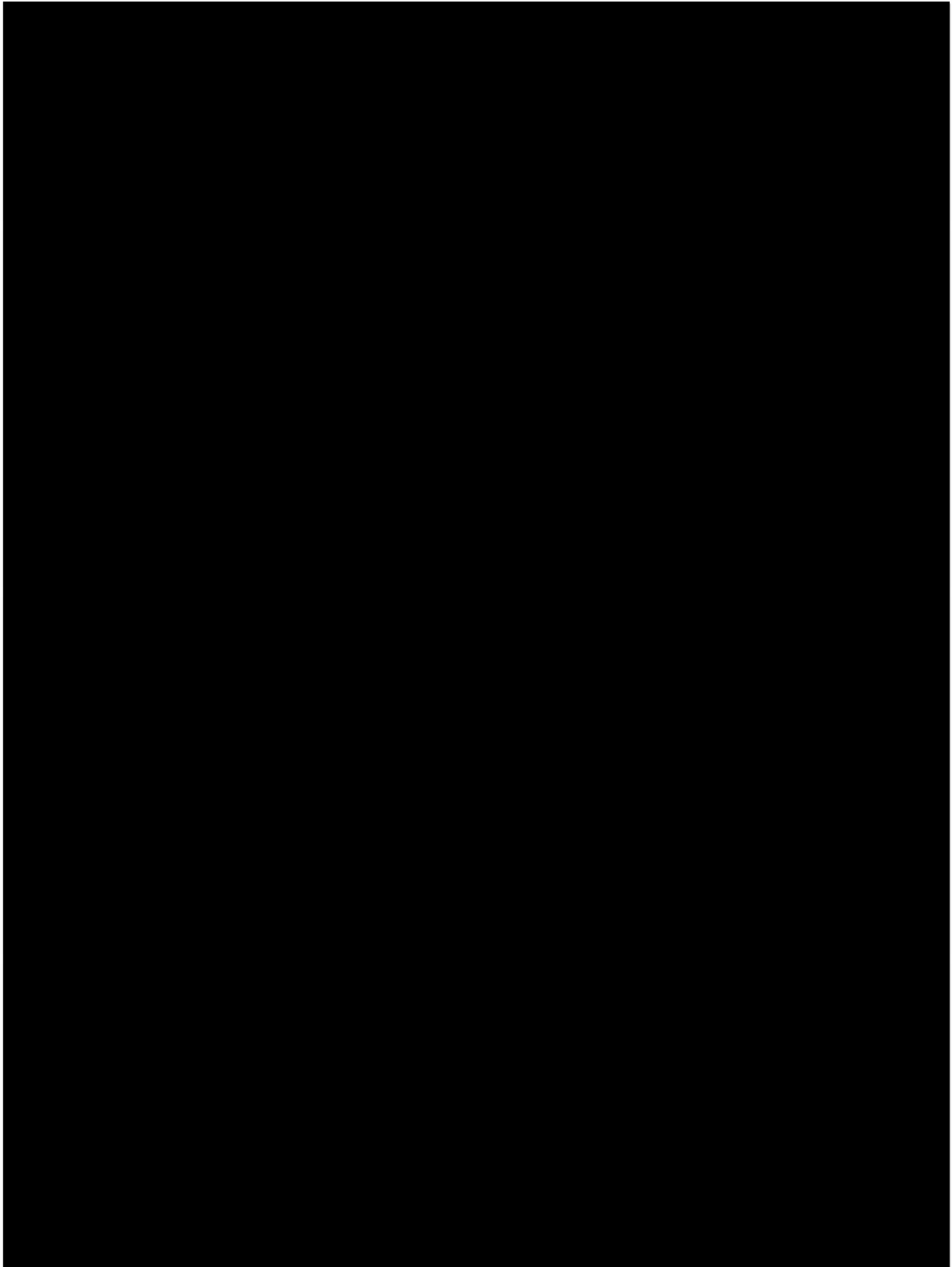
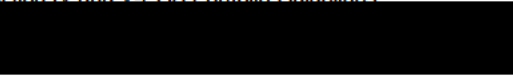


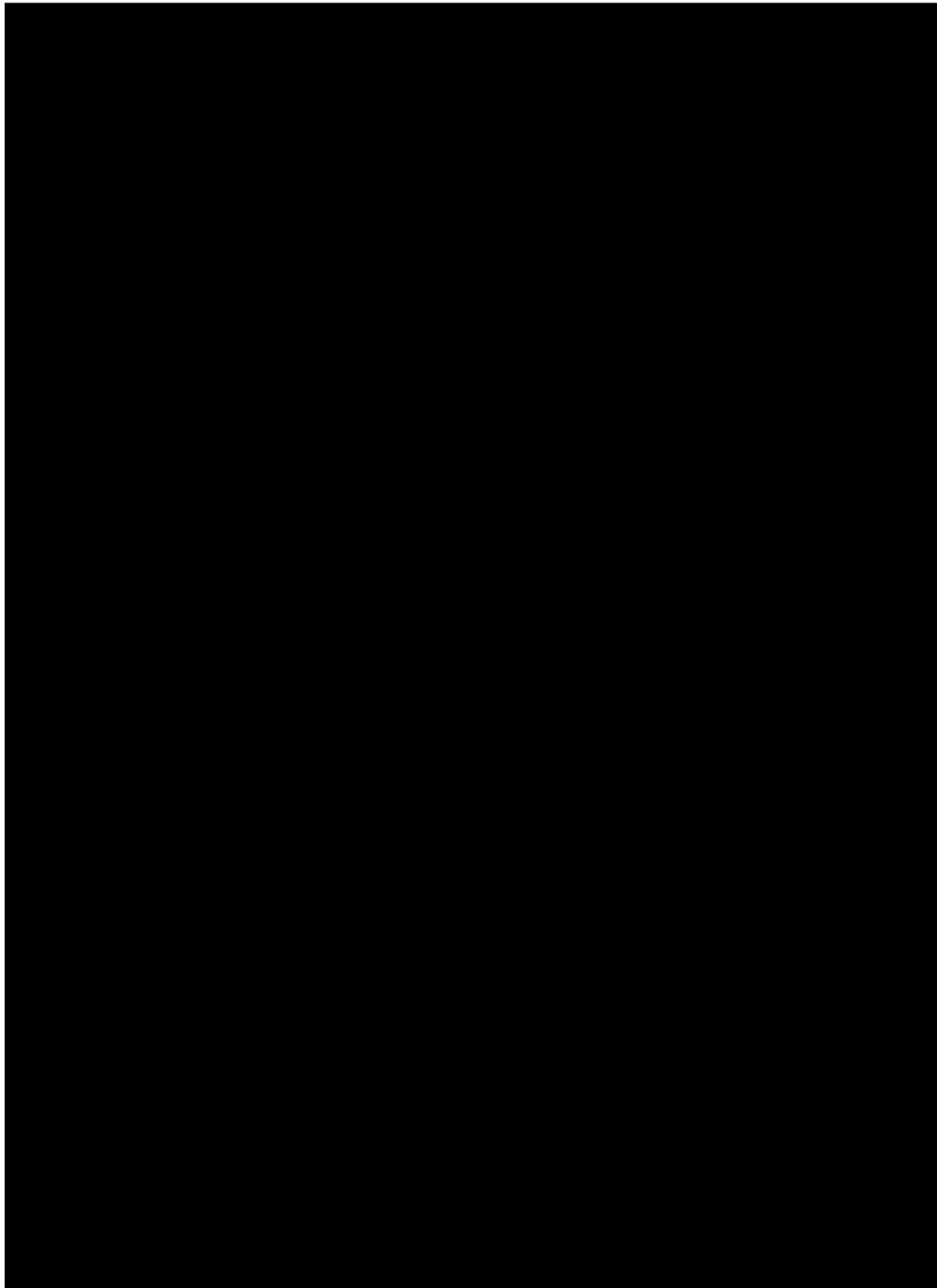


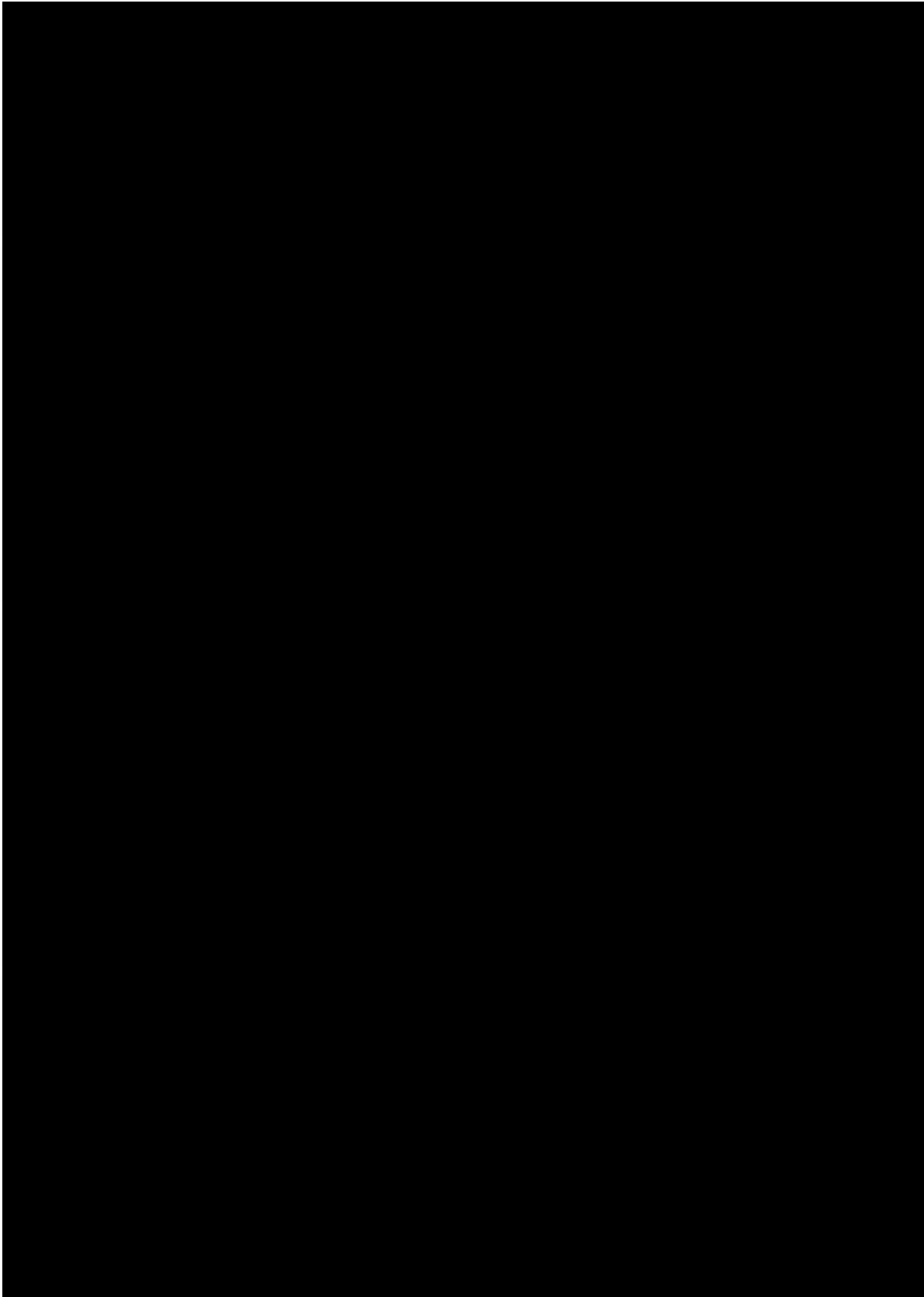


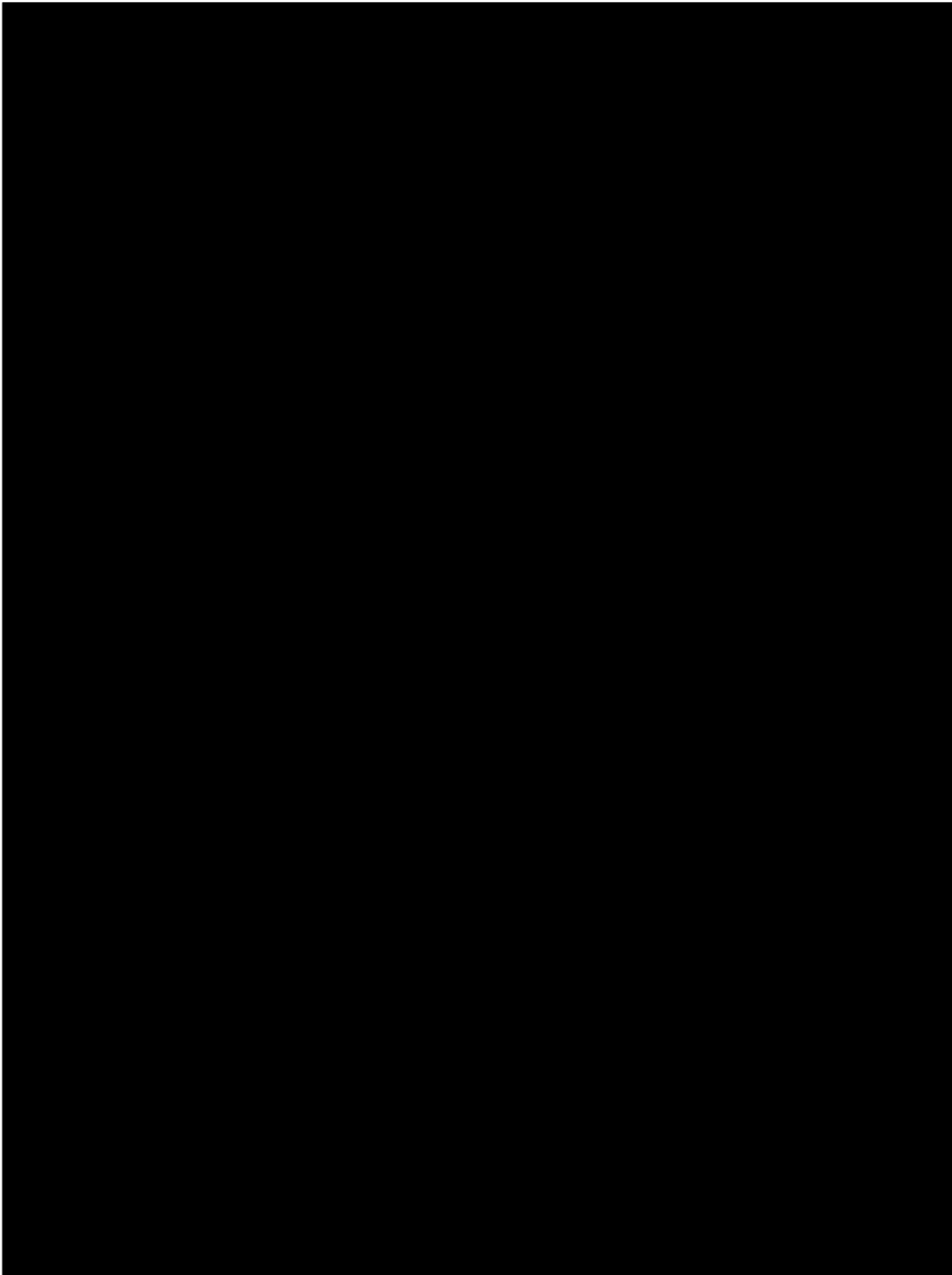


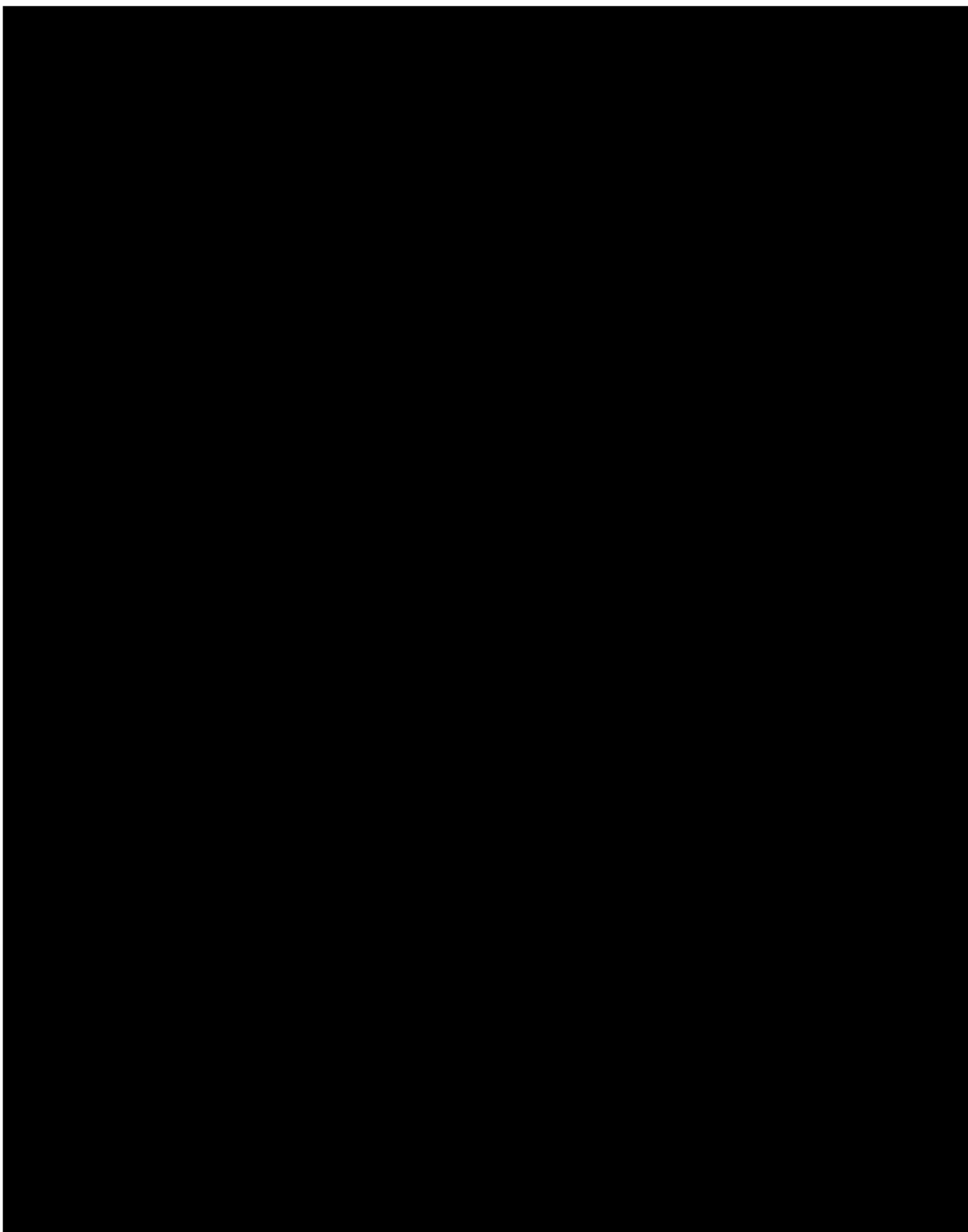


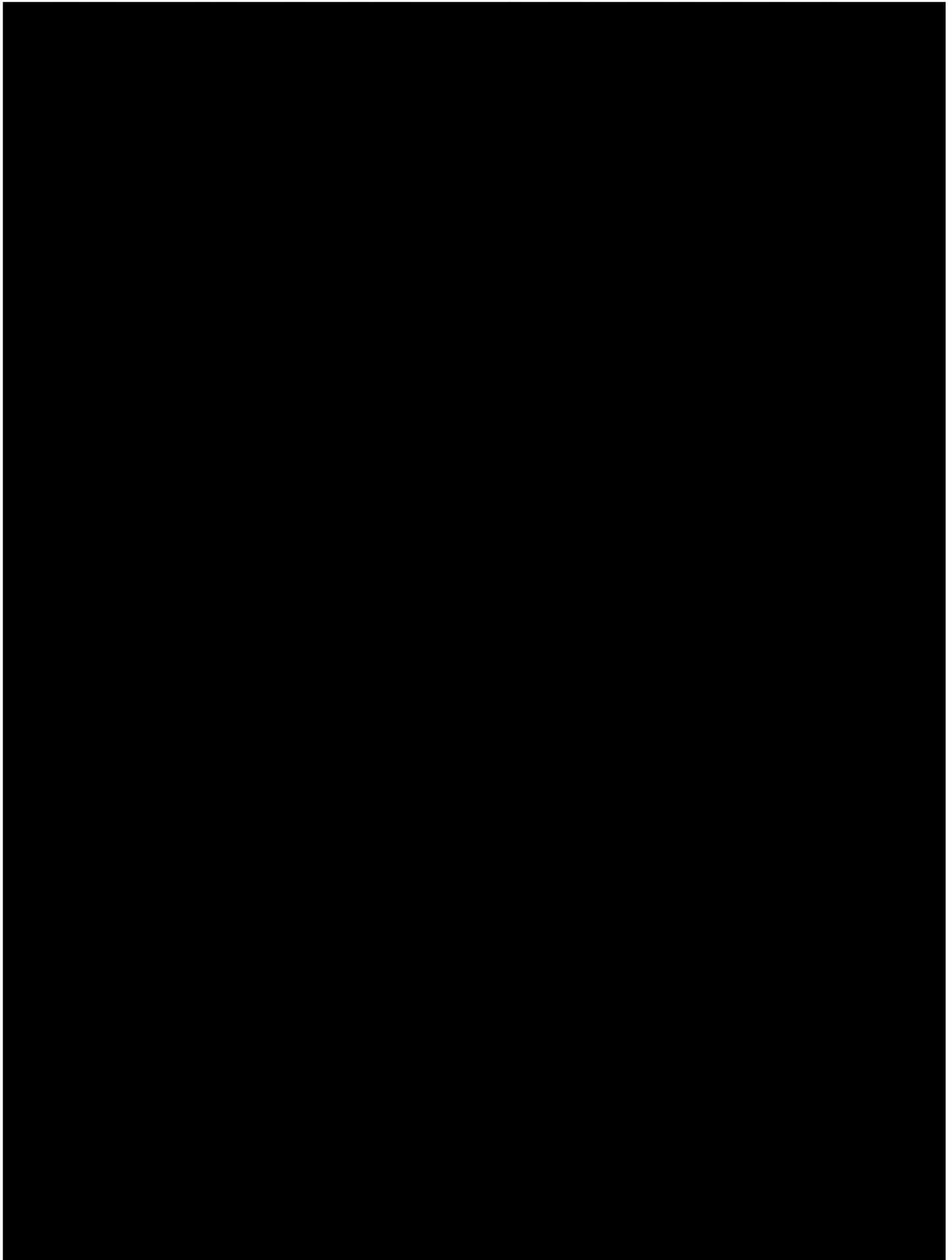


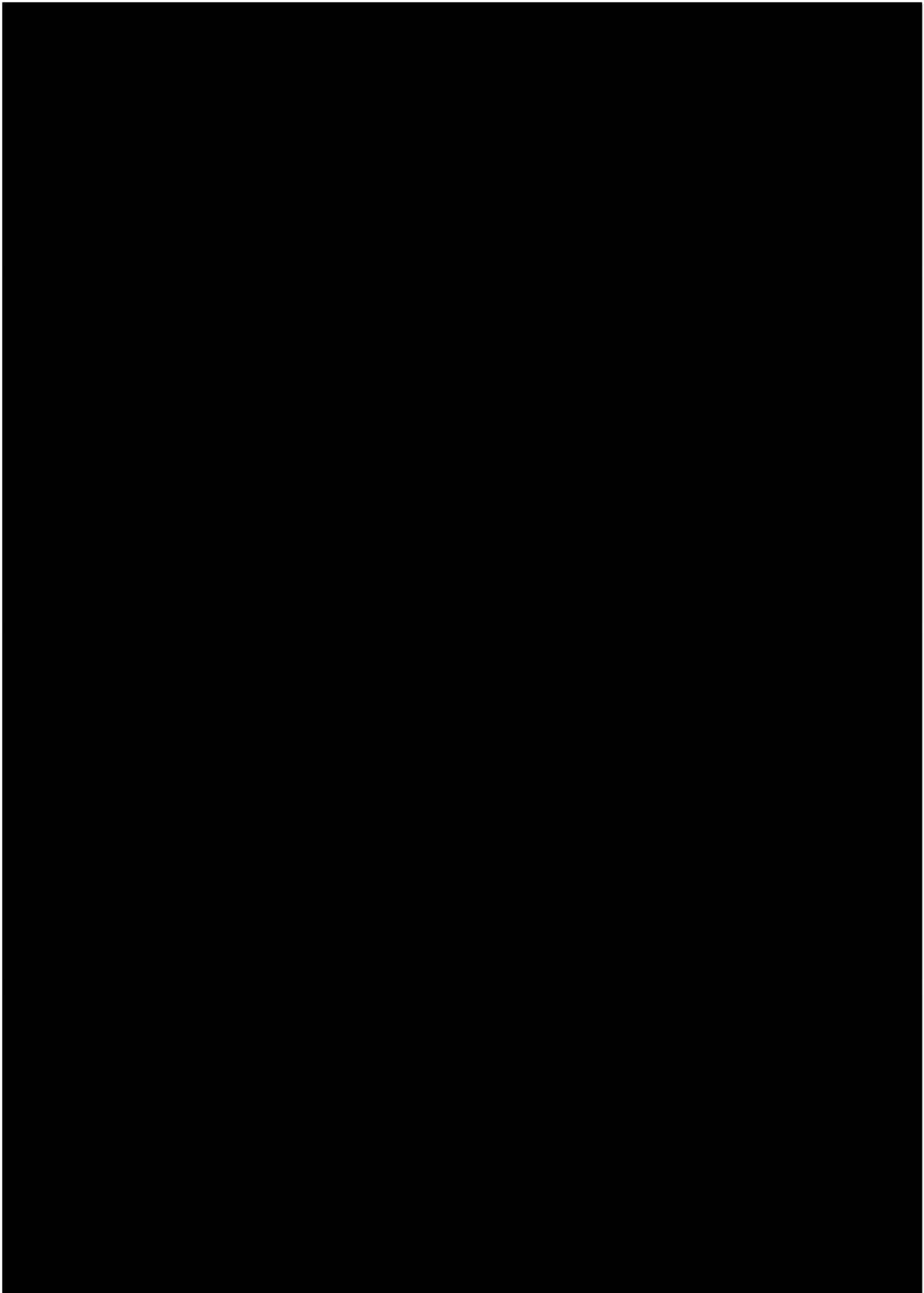


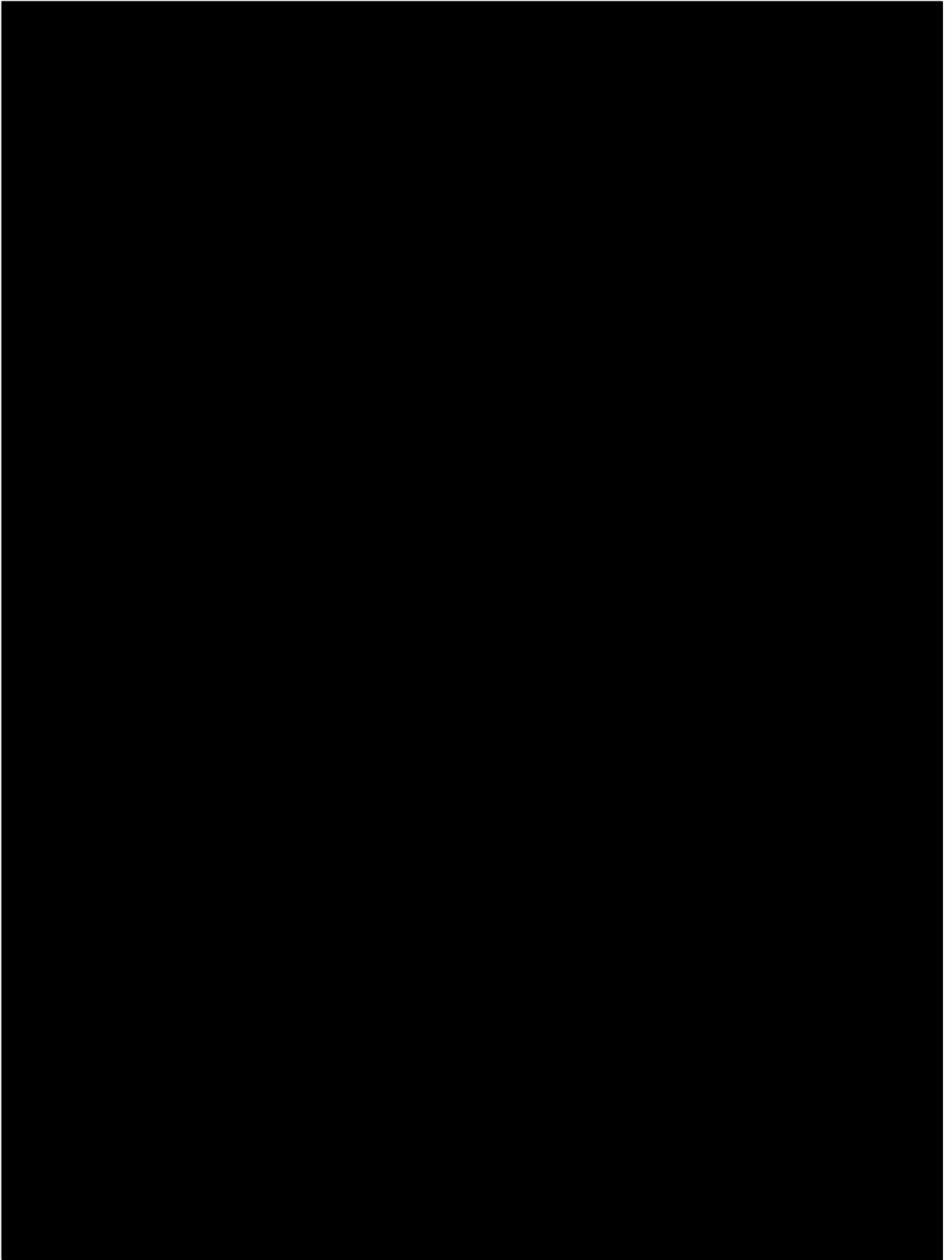


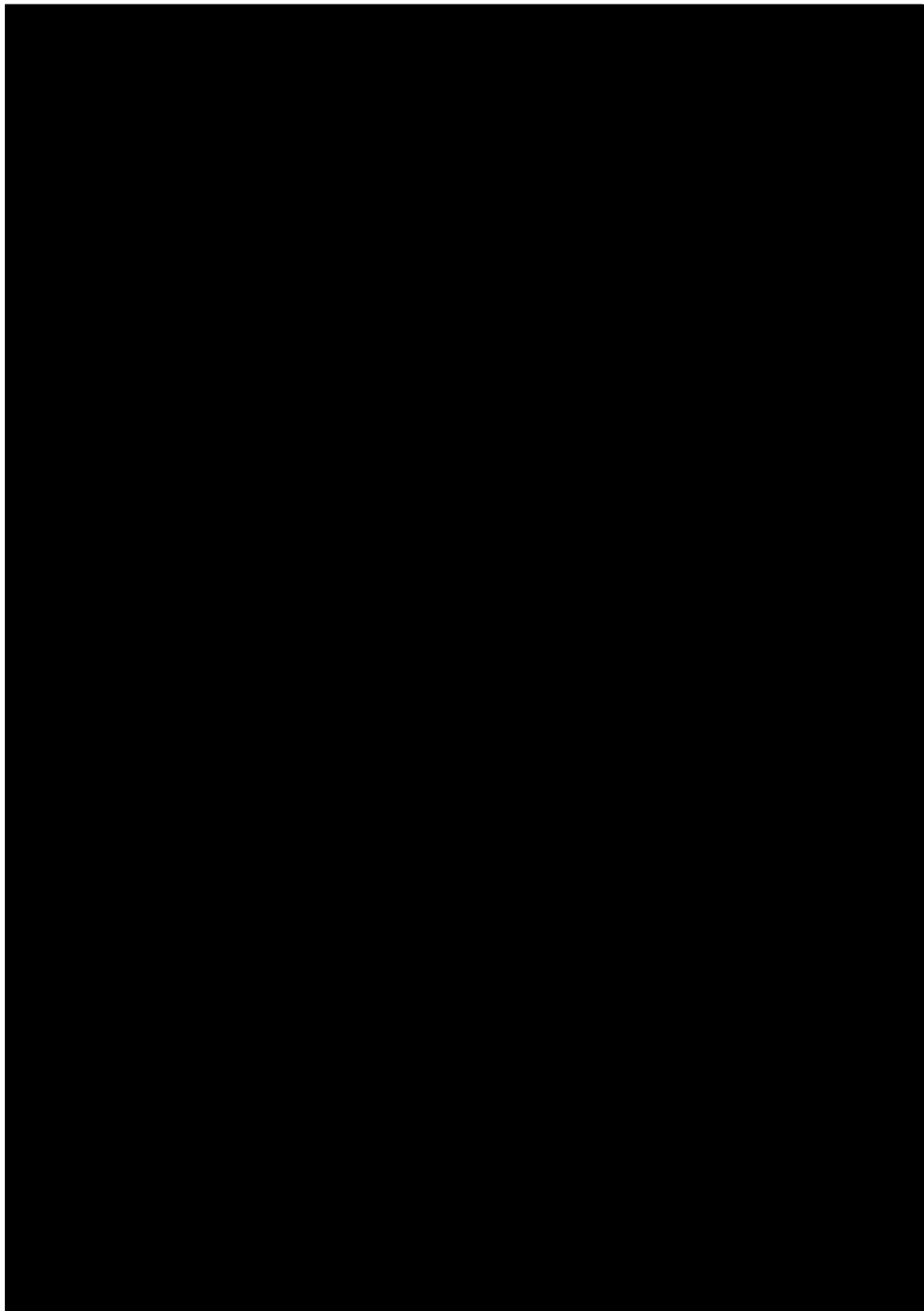












Section V.7 - Storage

Workpapers should include the following information about natural gas storage included in the portfolio upon which that PGA is based.

- a) **Type of storage (e.g. depleted field, salt dome).**
See Table 1 below.
- b) **Location of each storage facility.**
See Table 1 below.
- c) **Total level of storage in terms of deliverability and capacity held during the gas year.**
See Table 1 below.

TABLE 1

| Facility | Max. Daily Rate (Dth/day) | Max. Seasonal Level (Dth) |
|--|------------------------------|------------------------------|
| Jackson Prairie - aquifer - Chehalis, WA | 46,030 | 1,120,288 |
| J. Aron Storage - virtual storage - Alberta, Canada | 16,813 | 1,530,000 |
| Mist (share allocated to Utility) - depleted field - Mist, OR | 305,000 | 11,266,191 |
| Portland LNG - LNG Plant - Portland, OR | 130,680 | 490,050 |
| Newport LNG - LNG Plant - Newport, OR | 65,340 | 827,640 |

- d) **Historical (five years) gas supply delivered to storage, both annual total and by month.**
See Table 2 below.
- e) **Historical (five years) gas supply withdrawn from storage, both annual total and by month**
See Table 2 below.

TABLE 2

| NORTHWEST NATURAL GAS COMPANY All Sites Thermo Summary | | | | | | | | | | | | |
|---|-------------------|------------------|---------|----------------------|------------------|---------------|-----------------|-------------------------|---------------|------------------|---------|--|
| MONTH | BEGINNING BALANCE | | RATE | ISSUES (Withdrawals) | | LIQUEFIED | | INJECTIONS (Deliveries) | | ENDING BALANCE | | |
| | THERMS | AMOUNT | | THERMS | AMOUNT | THERMS | AMOUNT | RATE | THERMS | AMOUNT | RATE | |
| TOTAL 2012 ACTIVITY | | | | | | | | | | | | |
| | | | | 81,123,646 | \$ | 31,859,704.92 | 71,372,071 | \$ | 20,436,990.77 | | | |
| TOTAL 2013 ACTIVITY | | | | | | | | | | | | |
| | | | | 117,570,946 | \$ | 43,322,817.21 | 107,031,306 | \$ | 35,842,132.15 | | | |
| TOTAL 2014 ACTIVITY | | | | | | | | | | | | |
| | | | | 96,157,731 | \$ | 39,589,149.96 | 134,401,574 | \$ | 57,258,123.80 | | | |
| TOTAL 2015 ACTIVITY | | | | | | | | | | | | |
| | | | | 57,001,900 | \$ | 22,363,301 | 58,510,039 | \$ | 14,101,981 | | | |
| TOTAL 2016 ACTIVITY | | | | | | | | | | | | |
| | | | | 71,865,619 | \$ | 23,171,315 | 38,167,354 | \$ | 7,296,506 | | | |
| TOTAL 2017 ACTIVITY | | | | | | | | | | | | |
| | | | | 44,139,434 | \$ | 12,898,679 | 45,007,772 | \$ | 10,819,422 | | | |
| Jan-12 | 159,980,643 | \$ 74,284,792.14 | 0.46434 | 11,911,891 | \$ 4,669,327.57 | 2,279,590 | \$ 649,110.97 | 0.28475 | 150,348,342 | \$ 70,264,575.54 | 0.46735 | |
| Feb | 150,348,342 | \$ 70,264,575.54 | 0.46735 | 8,672,041 | \$ 3,187,445.76 | 348,590 | \$ 88,897.46 | 0.25502 | 142,024,891 | \$ 67,166,027.24 | 0.47292 | |
| Mar | 142,024,891 | \$ 67,166,027.24 | 0.47292 | 12,658,159 | \$ 5,455,394.54 | 3,460,810 | \$ 739,939.28 | 0.21381 | 132,827,542 | \$ 62,450,571.98 | 0.47016 | |
| Apr | 132,827,542 | \$ 62,450,571.98 | 0.47016 | 23,051,846 | \$ 10,194,050.58 | 4,500,360 | \$ 869,525.78 | 0.19321 | 114,276,056 | \$ 53,126,047.18 | 0.46489 | |
| May | 114,276,056 | \$ 53,126,047.18 | 0.46489 | 2,790,265 | \$ 1,071,649.57 | 3,842,187 | \$ 895,679.98 | 0.23312 | 115,327,978 | \$ 52,950,077.59 | 0.45913 | |
| Jun | 115,327,978 | \$ 52,950,077.59 | 0.45913 | 2,209,903 | \$ 643,407.48 | 6,310,010 | \$ 1,367,411.71 | 0.21671 | 119,428,085 | \$ 53,674,081.82 | 0.44943 | |
| Jul | 119,428,085 | \$ 53,674,081.82 | 0.44943 | 922,095 | \$ 285,082.42 | 7,056,836 | \$ 1,790,152.04 | 0.25368 | 125,562,826 | \$ 55,179,151.44 | 0.43945 | |
| Aug | 125,562,826 | \$ 55,179,151.44 | 0.43945 | 289,508 | \$ 151,844.55 | 3,112,036 | \$ 792,432.45 | 0.25463 | 128,385,354 | \$ 58,314,407.45 | 0.42173 | |
| Sep | 128,385,354 | \$ 58,314,407.45 | 0.42173 | 207,941 | \$ 113,206.61 | 10,098,405 | \$ 2,607,874.72 | 0.25825 | 138,275,818 | \$ 64,964,226.47 | 0.41509 | |
| Oct | 138,275,818 | \$ 64,964,226.47 | 0.41509 | 5,444,783 | \$ 1,384,452.69 | 25,766,796 | \$ 8,855,633.86 | 0.34368 | 158,597,831 | \$ 65,785,588.62 | 0.41480 | |
| Nov | 158,597,831 | \$ 65,785,588.62 | 0.41480 | 4,580,684 | \$ 1,750,833.09 | 2,489,966 | \$ 929,470.94 | 0.37329 | 156,507,113 | \$ 64,964,226.47 | 0.41509 | |
| Dec | 156,507,113 | \$ 64,964,226.47 | 0.41509 | 8,384,530 | \$ 2,953,010.05 | 2,106,485 | \$ 850,861.58 | 0.40392 | 150,229,068 | \$ 62,862,077.99 | 0.41844 | |

f) An explanation of the methodology utilized by the LDC to price storage injections and withdrawals, as well as the total and average (per unit) cost of storage gas.

The price of gas placed into storage, classed as working inventory, will be the average cost of gas defined as the average commodity cost of gas delivered to the city gate (utilizing unhedged discretionary sources first: i.e., spot gas first, then swing, and base load term supplies last. If storage injections exceed unhedged gas purchases, then average cost of hedged gas would be used to value the remainder of the storage injections.) This price would represent commodity cost, transportation cost, and fuel-in-kind (FIK) at either the NWN city gas (internal storage) or at the external storage site. In addition, this price will include all storage reservation charges.

This pricing policy will apply to all storage locations owned or under contract to the NNG, with exceptions as noted.

* When the contract for a storage site includes a provision for the price of the gas placed into storage, the price shall be the price as defined by the agreement.

* Direct associated costs, such as liquefaction fees, fuel-in-kind and actual material costs incurred can be added to the base cost when determined significant.

* Injections into virtual storage sites are valued using specific commodity deals plus added costs for fuel and to maintain specific contract terms for each site.

Withdrawals at each facility are priced at the average inventory price as established at the beginning of each month. The beginning of the month cost at each facility is adjusted for any withdrawals and any injections to create the end of the month cost, which then becomes the beginning of the month cost for the next month.

g) Copies of all contracts or other agreements and tariffs that control the LDC's use of the storage facilities included in the current portfolio.

See below for the Form of Rate Schedule SGS-2F Service Agreement and the Alberta storage contract¹.

¹ Use of the storage facilities also requires the use of transportation service agreements controlled by the tariffs of the applicable upstream pipelines as and when needed to inject gas into and withdraw gas from each of these facilities.

SGS-2F 01/05/07

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FORM OF RATE SCHEDULE SGS-2F SERVICE AGREEMENT

Rate Schedule SGS-2F Service Agreement

Contract No. 100502

THIS SERVICE AGREEMENT (Agreement) by and between Northwest Pipeline GP (Transporter) and Northwest Natural Gas Company (Shipper) restates the Service Agreement made and entered into on January 01, 1998.

WHEREAS:

- A Pursuant to Section 11.4 of the General Terms and Conditions of Transporter's FERC Gas Tariff, Transporter and Shipper desire to restate the Service Agreement dated January 01, 1998 ("Contract # 100502") in the format of Northwest's currently effective Form of Service Agreement and to make certain additional non-substantive changes, while preserving all pre-existing, substantive contractual rights.
- B Shipper originally acquired capacity by entering into a binding precedent agreement through the open season for incremental firm storage service at Jackson Prairie; as authorized by FERC in Docket No. CP06-416.

THEREFORE, in consideration of the premises and mutual covenants set forth herein, Transporter and Shipper agree as follows:

1. **Tariff Incorporation.** Rate Schedule SGS-2F and the General Terms and Conditions (GT&C) that apply to Rate Schedule SGS-2F, as such may be revised from time to time in Transporter's FERC Gas Tariff (Tariff), are incorporated by reference as part of this Agreement, except to the extent that any provisions thereof may be modified by non-conforming provisions herein.
2. **Storage Service.** Subject to the terms and conditions that apply to service under this Agreement, Transporter agrees to inject, store and withdraw natural gas for Shipper, on a firm basis. Shipper may request Transporter to withdraw volumes in excess of Shipper's Contract Demand on a best efforts basis as provided in Rate Schedule SGS-2F. The Contract Demand and Storage Capacity are set forth on Exhibit A.
3. **Storage Rates.** Shipper agrees to pay Transporter for all services rendered under this Agreement at the rates set forth or referenced herein. The maximum currently effective rates (Recourse Rates) set forth in the Statement of Rates in the Tariff, as revised from time to time, that apply to the Rate Schedule SGS-2F customer category identified on Exhibit A will apply to service hereunder unless and to the extent that discounted Recourse Rates or awarded capacity release rates apply as set forth on Exhibit A or negotiated rates apply as set forth on Exhibit D.
4. **Service Term.** This Agreement becomes effective on the date first set forth above. The primary term begin date for the storage service hereunder is set forth on Exhibit A. This Agreement will remain in full force and effect through the primary term end date set forth on Exhibit A and, if Exhibit A indicates that an evergreen provision applies, through the established evergreen rollover periods thereafter until terminated in accordance with the notice requirements under the applicable evergreen provision.
5. **Non-Conforming Provisions.** All aspects in which this Agreement deviates from the Tariff, if any, are set forth as non-conforming provisions on Exhibit B. If Exhibit B includes any material non-conforming provisions, Transporter will file the Agreement with the Federal Energy Regulatory Commission (Commission) and the effectiveness of such non-conforming provisions will be subject to the Commission acceptance of Transporter's filing of the non-conforming Agreement.
6. **Capacity Release.** If Shipper is a temporary capacity release Replacement Shipper, any capacity release conditions, including recall rights and the amount of the Releasing Shipper's Working Gas Quantity released to Shipper for the initial Storage Cycle, are set forth on Exhibit A.
7. **Exhibit Incorporation.** Exhibit A is attached hereto and incorporated as part of this Agreement. If Exhibits B and/or D apply, as noted on Exhibit A to this Agreement, then such Exhibits also are attached hereto and incorporated as part of this Agreement.
8. **Regulatory Authorization.** Storage service under this Agreement is authorized pursuant to the Commission regulations set forth on Exhibit A.
9. **Superseded Agreements.** When this Agreement takes effect, it supersedes, cancels and terminates the following agreement(s): Original Service Agreement dated January 1, 1998.

IN WITNESS WHEREOF, Transporter and Shipper have executed this Restated Agreement on January 21, 2008.

Northwest Natural Gas Company

By: /s/

Northwest Pipeline GP

By: /s/

8/19/2009

SGS-2F 01/05/07

Page 2 of 3

Name: RANDOLPH S. FRIEDMAN
Title: DIRECTOR, GAS SUPPLY

Name: JANE F HARRISON
Title: MANAGER NWP MARKETING SERVICES

SGS-2F 01/05/07

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FORM OF RATE SCHEDULE SGS-2F SERVICE AGREEMENT
(Continued)

EXHIBIT A
(Dated January 21, 2008, Effective January 21, 2008)
to the
Rate Schedule SGS-2F Service Agreement
(Contract No. 100502)
between Northwest Pipeline GP
and Northwest Natural Gas Company

SERVICE DETAILS

1. Customer Category: Pre-Expansion Shipper
2. Contract Demand: 46,030 Dth per day
3. Storage Capacity: 1,120,288 Dth
4. Recourse or Discounted Recourse Storage Rates:
(Show Not Applicable if Exhibit D is attached.)
 - a. Demand Charge (per Dth of Contract Demand):
Maximum Currently Effective Tariff Rate
 - b. Capacity Demand Charge (per Dth of Storage Capacity):
Maximum Currently Effective Tariff Rate
 - c. Rate Discount Conditions Consistent with Section 3.2 of Rate Schedule SGS-2F:
Not Applicable
5. Service Term:
 - a. Primary Term Begin Date:
November 01, 1998
 - b. Primary Term End Date:
October 31, 2004
 - c. Evergreen Provision:
Yes, grandfathered unilateral evergreen under Section 15.3 of Rate Schedule SGS-2F
6. Regulatory Authorization: 18 CFR 284.223
7. Additional Exhibits:
 - Exhibit B No
 - Exhibit D No

8/19/2009

tariff

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TF0350 000004Pl26Original Sheet No. 50
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm

1. AVAILABILITY

This Rate Schedule is available to any Shipper for the purchase of natural gas storage service from Transporter when Shipper and Transporter have executed a Service Agreement for the storage of gas under this Rate Schedule and have arranged for the related transportation of gas to and from the Jackson Prairie Storage Project under one of Transporter's transportation rate schedules.

2. APPLICABILITY AND CHARACTER OF SERVICE

2.1 Applicability. This Rate Schedule shall apply to firm storage gas service consisting of Transporter's injection, storage and withdrawal of Shipper's gas at the Jackson Prairie Storage Project. The executed Service Agreement for service under this Rate Schedule will specify the Shipper category, i.e., whether the Shipper is a Pre-Expansion Shipper or an Expansion Shipper. The Jackson Prairie Storage Project capacity available for this Rate Schedule will be Transporter's undivided interest as an owner in the Project, excluding any portion of such interest which may be authorized for use by Transporter for transportation balancing. Delivery of natural gas by Shipper to Transporter for injection and by Transporter to Shipper upon withdrawal shall be at the point of interconnection between the Jackson Prairie Storage Project and Transporter's main transmission line.

2.2 Character of Service. Storage gas service rendered to Shipper under this Rate Schedule, up to Shipper's Contract Demand and Storage Capacity and subject to the limitations of this Rate Schedule and the executed Service Agreement, shall be firm and shall not be subject to curtailment or interruption except as provided in Sections 9, 10, 12, and 14 of the General Terms and Conditions.

2.3 Capacity Release. Shippers releasing firm storage rights shall do so in accordance with the capacity release provisions outlined in Section 22 of the General Terms and Conditions. Any such release is subject to the terms and conditions of this Rate Schedule.

3. MONTHLY RATE

Each month, Shipper will pay Transporter for service rendered under this Rate Schedule the amounts specified in this Section 3, as applicable.

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TF0351 0010004P126First Revised Sheet No. 51
TF04 Original Sheet No. 51
TF05Laren M. Gertsch, Director
TF06092508 110108

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

3.1 Storage Service. The sum of (a), (b) and (c) below:

- (a) Demand Charge: The sum of the daily product of Shipper's Contract Demand and the Demand Charge stated on Sheet No. of this Tariff that applies to the customer category identified in the Service Agreement.
- (b) Capacity Demand Charge: The sum of the daily product of Shipper's Storage Capacity and the Capacity Demand Charge stated on Sheet No. 7 of this Tariff that applies to the customer category identified in the Service Agreement.

The related transportation of gas to and from the Jackson Prairie storage facility shall be subject to separate transportation charges under applicable open-access Rate Schedules. The rates set forth in the sub-paragraphs above are exclusive of the aforementioned transportation charges.

3.2 Discounted Recourse Rates. Transporter reserves the right to discount at any time the Recourse Rates for any individual Shipper under any service agreement without discounting any other Recourse Rates for that or another Shipper; provided, however, that such discounted Recourse Rates shall not be less than the Minimum Currently Effective Rates set forth on Sheet No. 7 of this Tariff, or any superseding tariff. Such discounted Recourse Rates may apply to specific volumes of gas such as volumes injected, withdrawn or stored above or below a certain level or all volumes if volumes exceed a certain level, and volumes of gas injected, withdrawn or stored during specific time periods. If Transporter discounts any Recourse Rates to any Shipper, Transporter will file with the Commission any required reports reflecting such discounts.

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TF0352 0020004P126Second Revised Sheet No. 52
TF04 First Revised Sheet No. 52
TF05Laren M. Gertsch, Director
TF06012109 022009
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

3.3 Charges for Capacity Release Service: The rates for capacity release service are set forth in Sheet No. 7. See Section 22 of the General Terms and Conditions for information about rates for capacity release service, including information about acceptable bids. In the event of a base tariff maximum and/or minimum rate change, the Replacement Shipper will be obligated to pay:

(a) the lesser of the awarded bid rate and the new maximum base tariff rate, or the greater of the awarded bid rate and the new minimum base tariff rate, as applicable, for the remaining term of the release for capacity release transactions with a term of more than one year and where the awarded bid rate was not tied to the maximum rate as it may change from time to time;

(b) the greater of the minimum base tariff rate and the awarded bid rate for the remaining term of the release for capacity release transactions with a term of one year or less that take effect on or before one year from the date on which Transporter is notified of the release and where the award bid rate was not tied to the maximum tariff rate; or

(c) the new maximum rate or, if applicable, the percentage of the new maximum rate for capacity release transactions where the awarded bid rate was tied to the maximum rate as it may change from time to time.

For capacity release service subject to demand charges, the payments by the Replacement Shipper shall be equal to the sum of the daily product of the accepted Demand Charge bid rate and the Contract Demand, plus the sum of the daily product of the accepted Capacity Demand Charge bid rate and the Storage Capacity.

For capacity release service subject to volumetric bid rates, the payments by the Replacement Shipper shall be equal to the accepted volumetric bid rate for withdrawals multiplied by the actual volumes withdrawn each day plus the accepted volumetric bid rate for storage multiplied by the actual volumes in storage each day.

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TF0352-A 0010004P156 First Revised Sheet No. 52-A
TF04 Original Sheet No. 52-A
TF05 Laren M. Gertsch, Director
TF06012109 022009
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

3. MONTHLY RATE (Continued)

The SGS-2F Volumetric Bid Charge will be calculated as set forth in section 3.1 herein except that (a) and (b) change as specified below

(a) Withdrawal Charge: Per Dth of Withdrawals during the applicable month.

(b) Storage Charge: Per Dth of Shipper's Working Gas Inventory per day.

3.4 Negotiated Rates. Notwithstanding the general provisions of this Section 3, if Transporter and Shipper mutually agree to Negotiated Rates for service hereunder, such Negotiated Rates will apply in lieu of the otherwise applicable rates identified in this Section 3.

4. MINIMUM MONTHLY BILL

Unless Transporter and Shipper mutually agree otherwise, the Minimum Monthly Bill will consist of the sum of the Demand and Capacity Demand Charges specified in Section 3 of this Rate Schedule, as applicable.

5. FUEL GAS REIMBURSEMENT

Shipper shall reimburse Transporter for fuel use in-kind, as detailed in Section 14 of the General Terms and Conditions.

6. CONTRACT DEMAND

The Contract Demand shall be the largest number of Dth Transporter is obligated to withdraw and deliver to Shipper, and Shipper is entitled to receive from Transporter, at Jackson Prairie on any one day, to the limitations set forth in Section 9 below, and shall be specified in the executed Service Agreement between Transporter and Shipper. Transporter's service obligation is limited to Shipper's Contract Demand, as adjusted for any released capacity pursuant to Section 22 of the General Terms and Conditions

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TF0352-B 0010004P156 First Revised Sheet No. 52-B
TF04 Original Sheet No. 52-B
TF05 Laren M. Gertsch, Director
TF06 012109 022009'
TF07

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

7. STORAGE CAPACITY

Shipper's Storage Capacity shall be the maximum quantity of gas in Dth which Transporter is obligated to store for Shipper's account and shall be specified in the executed Service Agreement between Transporter and Shipper. Transporter's service obligation is limited to Shipper's Storage Capacity, as adjusted for any released capacity pursuant to Section 22 of the General Terms and Conditions.

8. DEFINITIONS

8.1 A Storage Cycle is the twelve-month period beginning October 1 of any calendar year and ending September 30 of the following calendar year.

8.2 Shipper's Working Gas Inventory shall be the actual quantity of working gas in storage for Shipper's account at the beginning of any given day.

8.3 Shipper's Working Gas Quantity for a Storage Cycle shall be determined as of October 1 and shall be the lesser of:

(a) Shipper's Working Gas Inventory as of October 1, the beginning of the Storage Cycle; or

(b) The minimum quantity of Shipper's Working Gas Inventory at any time between August 31 and September 30 of the preceding Storage Cycle divided by 0.80; or

(c) The minimum quantity of Shipper's Working Gas Inventory at any time between June 30 and September 30 of the preceding Storage Cycle divided by 0.35.

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TF0353 000004P126Original Sheet No. 53
TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm
(Continued)

8. DEFINITIONS (Continued)

 In addition to the quantity calculated above, an Expansion Shipper's Working Gas Quantity will include any increases in its Storage Capacity during the current Storage Cycle.

 The above method of determining Shipper's Working Gas Quantity may be modified consistent with any comparable modification under the January 15, 1998 Gas Storage Project Agreement, or superseding agreement, permitted by the Jackson Prairie Storage Project Management Committee. A Shipper's Working Gas Quantity will be adjusted for any Working Gas Quantity released as indicated on Exhibit A to a Replacement Shipper's Service Agreement.

8.4 Shipper's Available Working Gas on any day during the Storage Cycle shall be equal to Shippers' Working Gas Inventory less Shipper's Unavailable Working Gas.

8.5 Shipper's Unavailable Working Gas on any day during the Storage Cycle shall be equal to the highest level of Shipper's Working Gas Inventory during the preceding days of the current Storage Cycle less Shipper's Working Gas Quantity.

9. WITHDRAWALS OF STORAGE GAS

9.1 General Procedure. When Shipper desires the withdrawal of gas under this Rate Schedule on any day, it shall give notice to Transporter, specifying the volume of gas within Shipper's Available Working Gas which it desires withdrawn under this Rate Schedule during such day. Transporter shall thereupon withdraw the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule and subject as necessary to confirmation of the nomination changes for the related transportation service agreement.

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TF04
TF05Laren M. Gertsch, Director
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm
(Continued)

9. WITHDRAWALS OF STORAGE GAS (Continued)

9.2 Withdrawal Obligation. Transporter's daily withdrawal obligation shall be at 100 percent of the Shipper's Contract Demand as long as Shipper's Available Working Gas is greater than or equal to 60 percent of Shipper's Storage Capacity. On any day when Shipper's Available Working gas is less than 60 percent of Shipper's Storage Capacity, Transporter's daily withdrawal obligation shall be reduced by two percent of Shipper's Contract Demand for each one percent that Shipper's Available Working Gas is less than 60 percent of Shipper's Storage Capacity, until a minimum daily withdrawal rate equal to 10 percent of Shipper's Contract Demand is reached.

10. INJECTIONS OF WORKING GAS FOR SHIPPER'S ACCOUNT

Shipper shall provide written notice to Transporter prior to May of each year, of the volumes of gas to be injected for the account of Shipper during the period of May 1 through September 30 of such year. When Shipper desires the injection of gas under this Rate Schedule on any day, it shall give notice to Transporter, specifying the volume of gas it desires injected under this Rate Schedule during such day, including the applicable fuel reimbursement requirements. Transporter shall thereupon inject the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule and subject to delivery of such volume, and shall retain any fuel use reimbursement furnished in-kind in accordance with Section 14 of the General Terms and Conditions in addition to any fuel reimbursement required from the part under whose Service Agreement the gas is to be transported to Jackson Prairie.

11. WITHDRAWALS AND INJECTIONS SUBSEQUENT TO THE INTRADAY 2 NOMINATION CYCLE

To the extent Transporter's existing transportation and storage obligations are not compromised, Shipper may request up to two changes in scheduled daily withdrawal or injection quantities following the Intraday 2 Nomination Cycle for the remainder of the Gas Day. Transporter will thereupon withdraw or inject the volume of gas so nominated, subject to the limitations set forth in this Rate Schedule including fuel gas reimbursement requirements and subject as necessary to confirmation of the nomination changes for the related transportation service agreement.

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TF05Laren M. Gertsch, Director
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

12. LIMITATIONS ON INJECTIONS AND WITHDRAWALS FROM STORAGE

Shipper may request Transporter to cause gas to be injected into or withdrawn from storage for Shipper's account at any time during the year. Available injection capacity will be allocated to each Shipper proportionate to such Shipper's Storage Capacity. In no event shall the balance of gas stored in Shipper's account exceed Shipper's Storage Capacity as defined under Section 6 of this Rate Schedule.

After the commencement of an annual Storage Cycle, withdrawals from Shipper's Available Working Gas may be replaced both to maintain deliverability and to restore the quantity available for withdrawals. Additional working gas may also be injected during the Storage Cycle; provided, however, that Shipper's Unavailable Working Gas as defined in Section 8 above shall not be available for withdrawal during the current Storage Cycle.

13. WITHDRAWALS IN EXCESS OF FIRM ENTITLEMENT (BEST-EFFORTS WITHDRAWALS)

Shipper may request Transporter to withdraw volumes in excess of Shipper's Contract Demand on a best-efforts basis; provided, however, that the total volume withdrawn may not exceed the level of Shipper's Available Working Gas. Transporter may make such excess withdrawal, consistent with the priority of service provisions contained in Section 12 of the General Terms and Conditions, if and to the extent that capacity is available to make such withdrawal after Transporter's needs for withdrawal capacity to satisfy its system balancing requirements have been met.

14. TRANSFER OF WORKING GAS INVENTORY

Shippers subject to either this Rate Schedule or to Rate Schedule SGS-2I may agree to transfer their respective Working Gas Inventories between themselves. Participating Shippers must notify Transporter's Marketing Services personnel of their intent to transfer such inventory in writing, prior to the beginning of the gas day in which such transfer will occur. Transfers of Working Gas Inventory may not result in any Shipper taking title to Working Gas Inventory volumes that exceed such Shipper's Rate Schedule SGS-2F Storage Capacity or Rate Schedule SGS-2I Interruptible Storage Capacity.

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TF0356 000004P126Original Sheet No. 56
TF04
TF05Laren M. Gertsch, Director
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

14. TRANSFER OF WORKING GAS INVENTORY (Continued)

Pursuant to the January 15, 1998 Gas Storage Project Agreement, owners of the Jackson Prairie Storage Project may transfer portions of their respective available working gas inventories, as defined in the Project Agreement, to each other. Upon agreement of the parties, and subject to the terms of the Project Agreement, Transporter may utilize its ownership account on behalf of a Rate Schedule SGS-2F Shipper to transfer such Shipper's Working Gas Inventory to an owner's available working gas inventory account. Conversely, an owner may transfer its available working gas inventory to a Rate Schedule SGS-2F Shipper's Working Gas Inventory account.

15. EVERGREEN PROVISION

15.1 Standard Unilateral Evergreen Provision. If Transporter and Shipper agree to include a standard unilateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

(a) The established rollover period will be one year.

(b) Shipper may terminate the Service Agreement in its entirety upon the primary term end date or upon the conclusion of any evergreen rollover period thereafter by giving written notice to Transporter so stating at least five years before the termination date.

(c) The termination notice required under Section 15.1(b) will be deemed given when posted on Transporter's Designated Site.

15.2 Standard Bi-Lateral Evergreen Provision. If Transporter and Shipper agree to include a standard bi-lateral evergreen provision as indicated on Exhibit A of the Service Agreement, the following conditions will apply:

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TF04
TF05Laren M. Gertsch, Director
TF06121907 013108
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RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION (Continued)

(a) The established rollover period will be:

(i) one month for a Service Agreement with a primary term of less than one year; or

(ii) one year for a Service Agreement with a primary term of one year or more.

(b) Either Transporter or Shipper may terminate the Service Agreement in its entirety upon the primary term end date or upon the conclusion of any evergreen rollover period thereafter by giving the other party termination notice at least:

(i) ten Business Days before the termination date if Section 15.2(a)(i) applies; or

(ii) one year before the termination date if Section 15.2(a)(ii) applies.

(c) The termination notice required under Section 15.2(b) will be deemed given when posted on Transporter's Designated Site. If Transporter gives termination notice, such termination notice also will be given via Internet E-mail or fax if specified by Shipper on the Business Associate Information form.

15.3 Grandfathered Unilateral Evergreen Provision. If a Shipper with Service Agreement containing a unilateral evergreen provision elects: (i) to restate such Service Agreement in the format of the Form of Service Agreement contained in this Tariff, or (ii) to permanently release all or a portion of its firm contract rights, including its unilateral evergreen rights, to a Replacement Shipper at the Maximum Base Tariff Rate pursuant to Section 22.5 of the General Terms and Conditions, then the Exhibit A of the applicable restated or replacement Service Agreement will indicate that the following grandfathered unilateral evergreen conditions will apply:

(a) The established rollover period will be one year, at Shipper's sole option.

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TF04
TF05Laren M. Gertsch, Director
TF06121907 013108

RATE SCHEDULE SGS-2F
Storage Gas Service - Firm (Continued)

15. EVERGREEN PROVISION (Continued)

(b) Shipper may terminate all or any portion of service under its Service Agreement either at the expiration of the primary term, or upon any anniversary thereafter, by giving written notice to Transporter so stating at least twelve months in advance.

(c) Shipper also will have the sole option to enter into a new Service Agreement for all or any portion of the service under its Service Agreement at or after the end of the primary term of its Service Agreement. It is Transporter's and Shipper's intent that this provision provide Shipper with a "contractual right to continue such service" and to provide Transporter with concurrent pregranted abandonment of any volume that Shipper terminates within the meaning of 18 CFR 284.221(d)(2)(i) as promulgated by Order No. 636 on May 8, 1992.

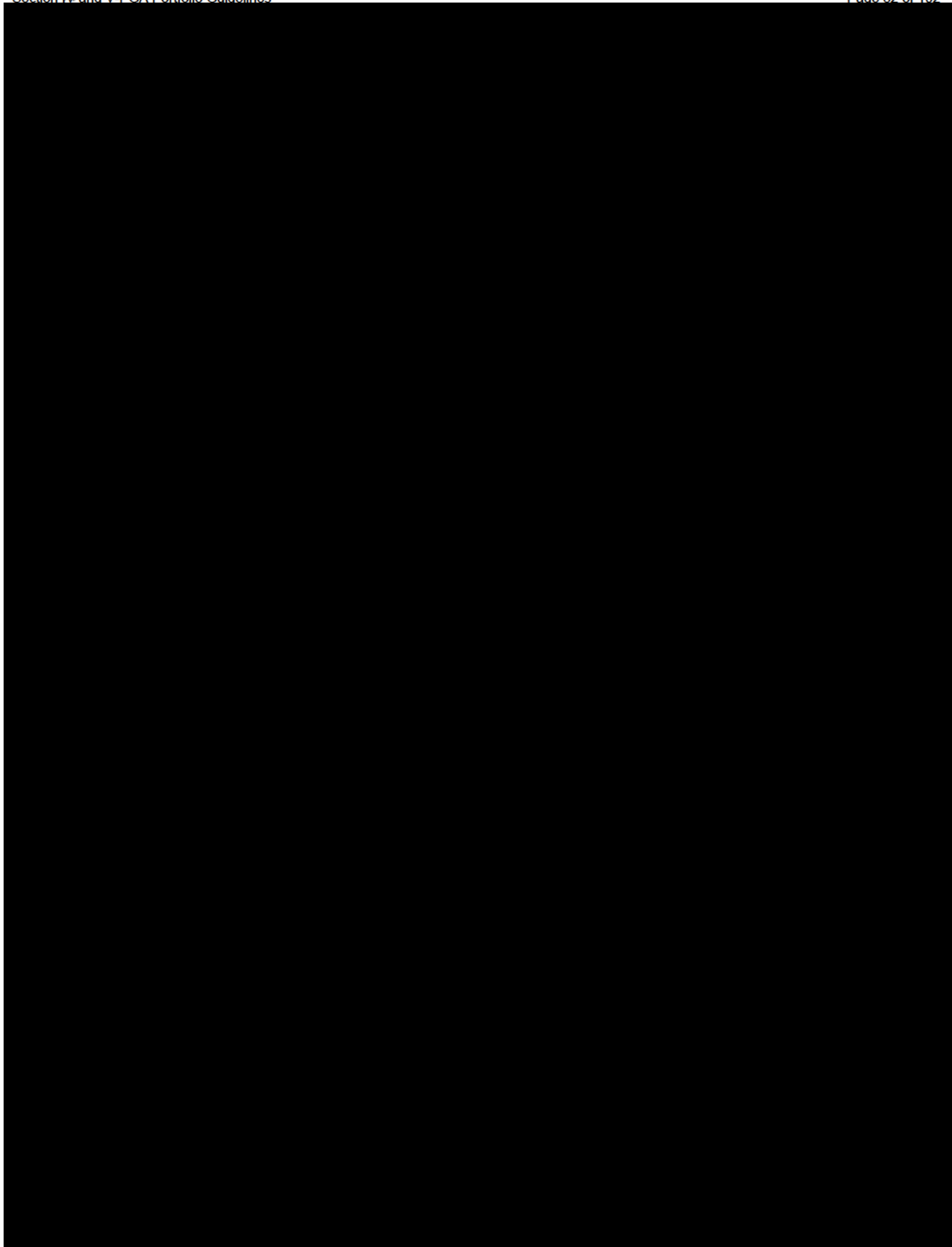
(d) The termination notice required under Section 15.3(b) will be deemed given when posted on Transporter's Designated Site.

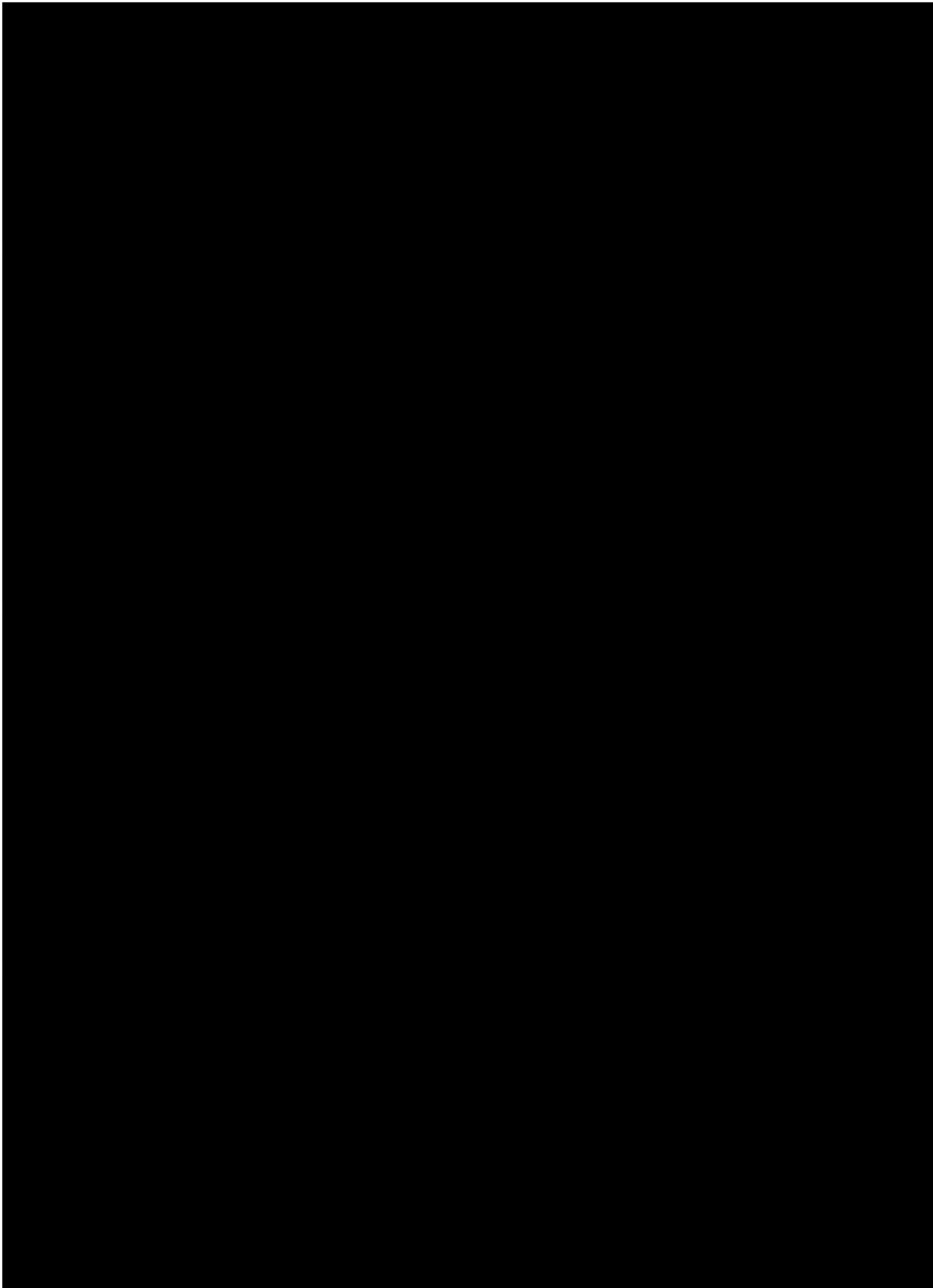
16. INTERIM BEST-EFFORTS WITHDRAWAL CHARGE REVENUE CREDITING

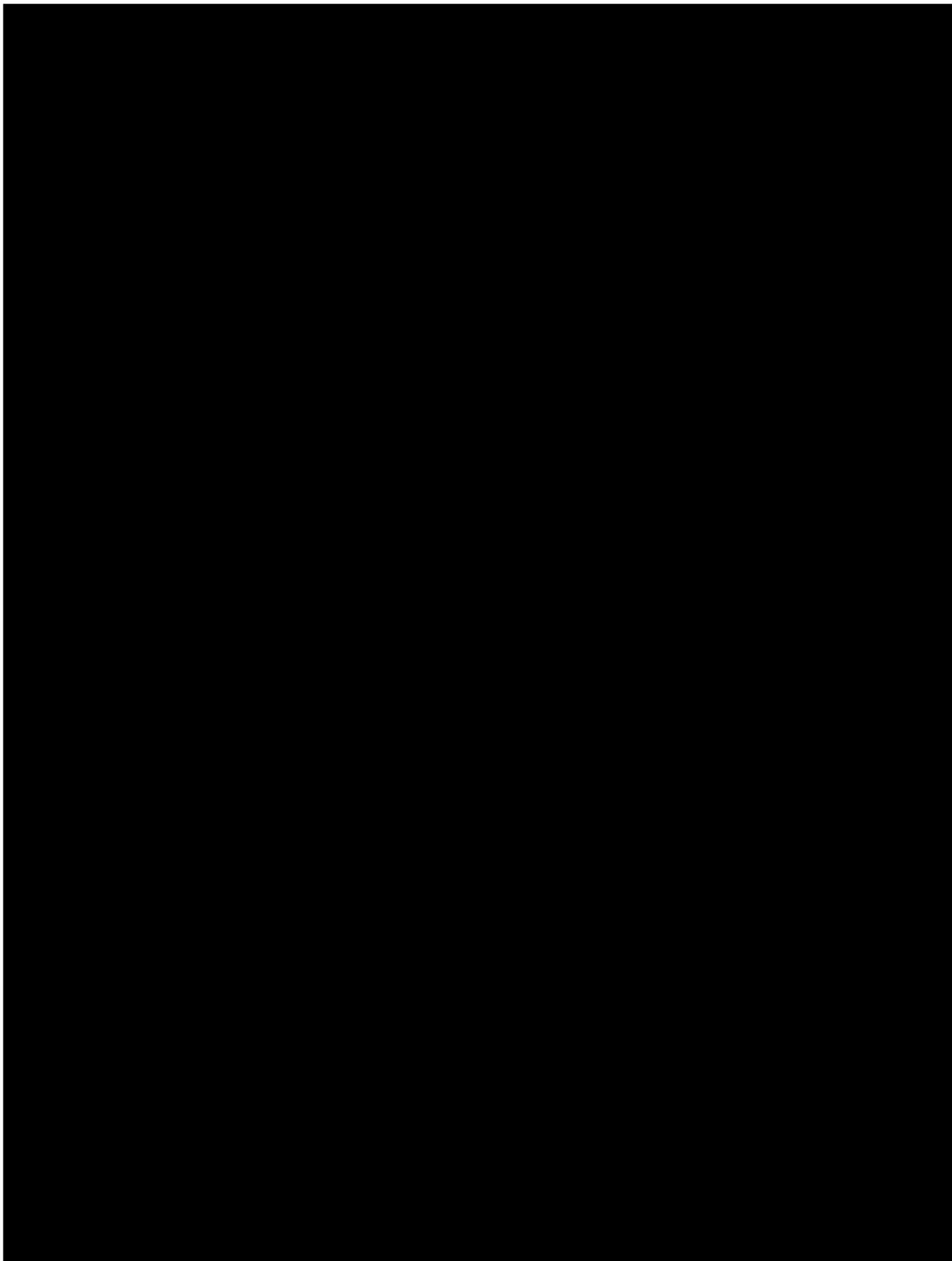
One hundred percent (100%) of Interim Best-Efforts Withdrawal Charge revenues received by Transporter pursuant to Section 3.1 will be credited to Rate Schedule SGS-2F Pre-Expansion Shippers, excluding such Shippers receiving service under capacity release Service Agreements. For each month Transporter receives Interim Best-Efforts Withdrawal Charge revenues, credits for such revenues will be allocated to the eligible Rate Schedule SGS-2F Pre-Expansion Shippers pro rata in proportion to the Demand Charge revenues, net of credits from capacity releases as described in Section 23 of the General Terms and Conditions, received from each eligible Rate Schedule SGS-2F Pre-Expansion Shipper for that month. Such allocated monthly revenue credits will be accrued during a calendar year and reflected as credit billing adjustments on the eligible Shippers' March invoices following such calendar year.

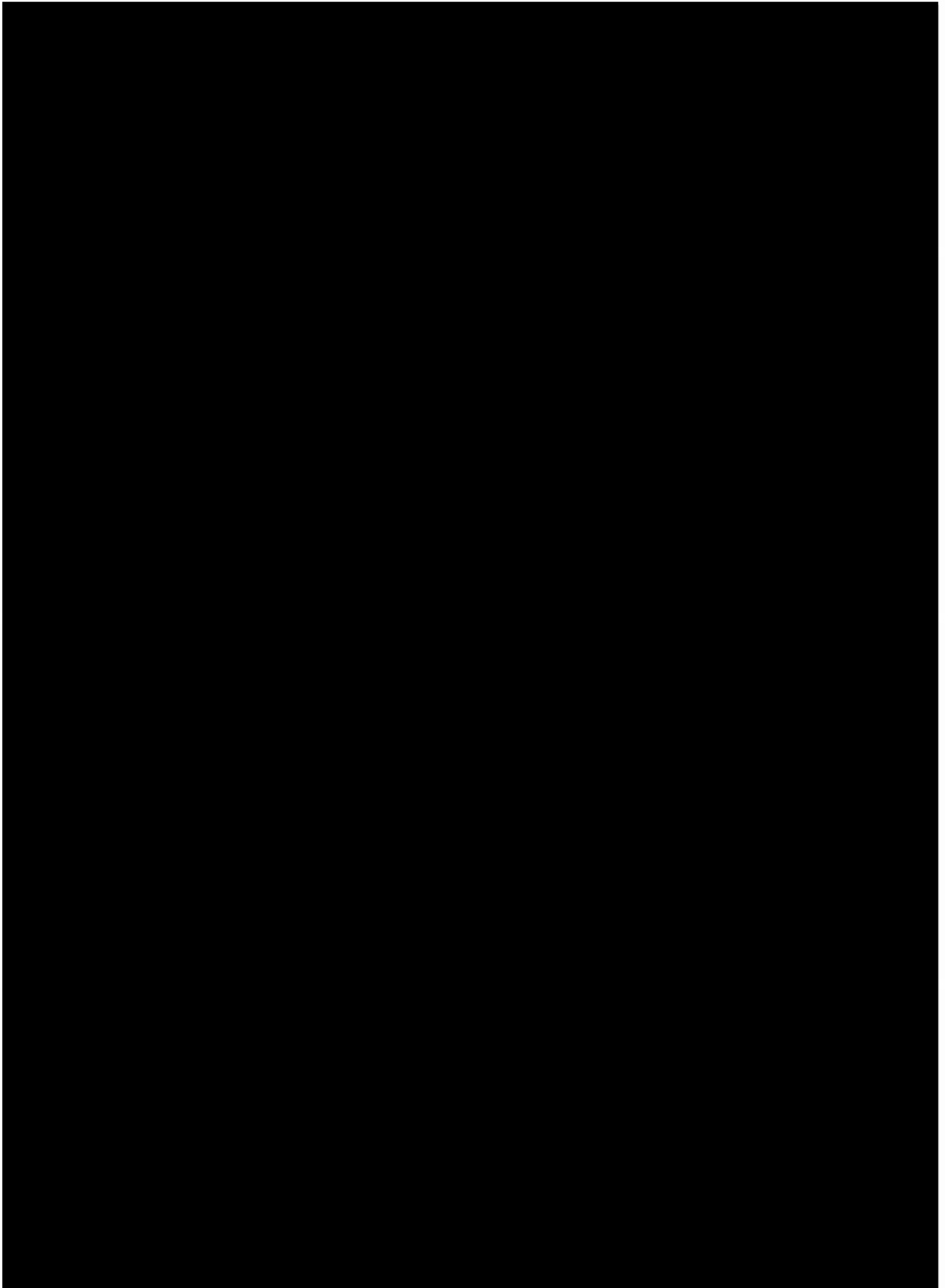
17. GENERAL TERMS AND CONDITIONS

The General Terms and Conditions contained in this Tariff, except Sections 13, 16 and 21 and except as modified in the executed Service Agreement, are applicable to this Rate Schedule and are hereby made a part hereof.







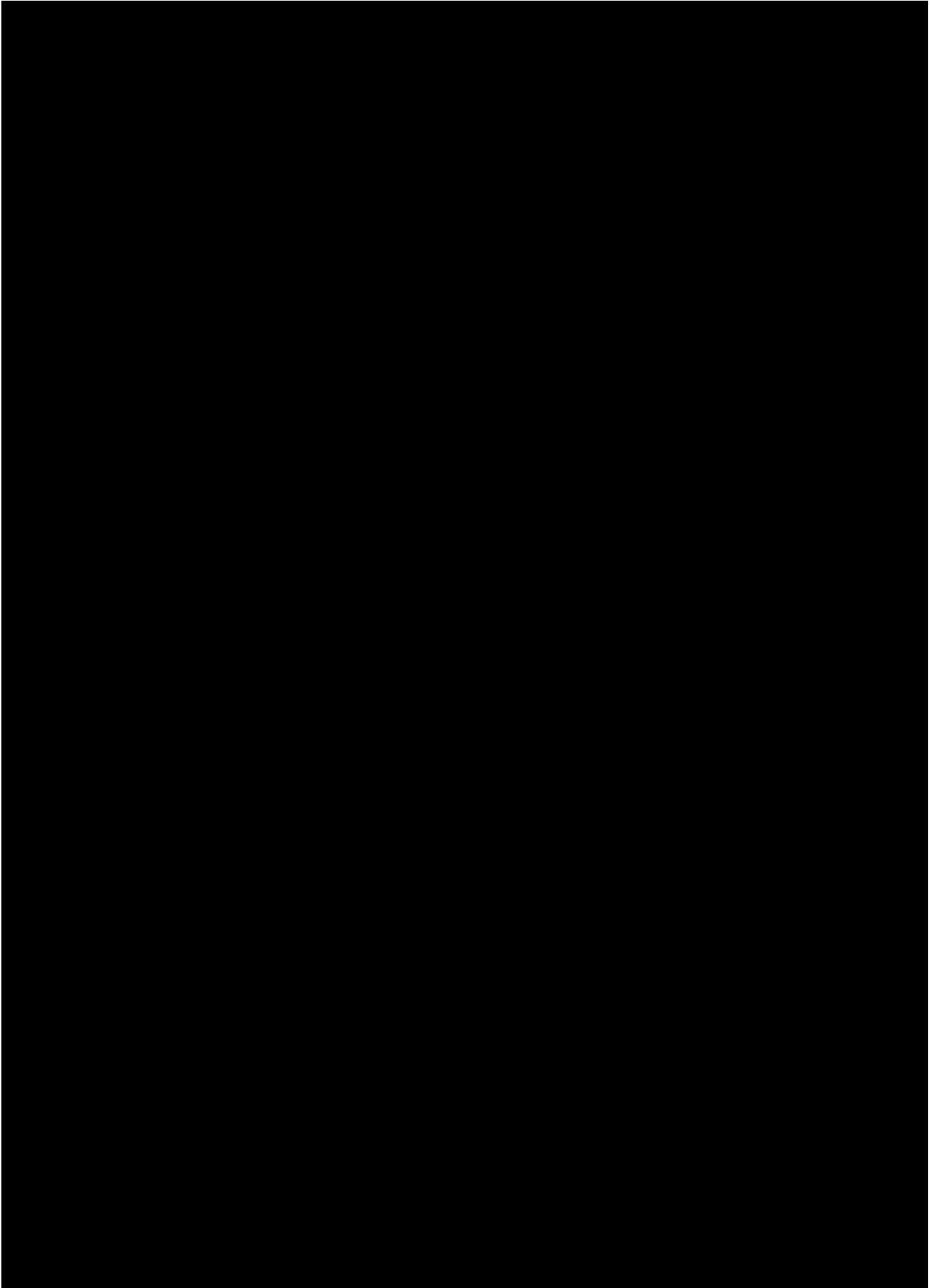


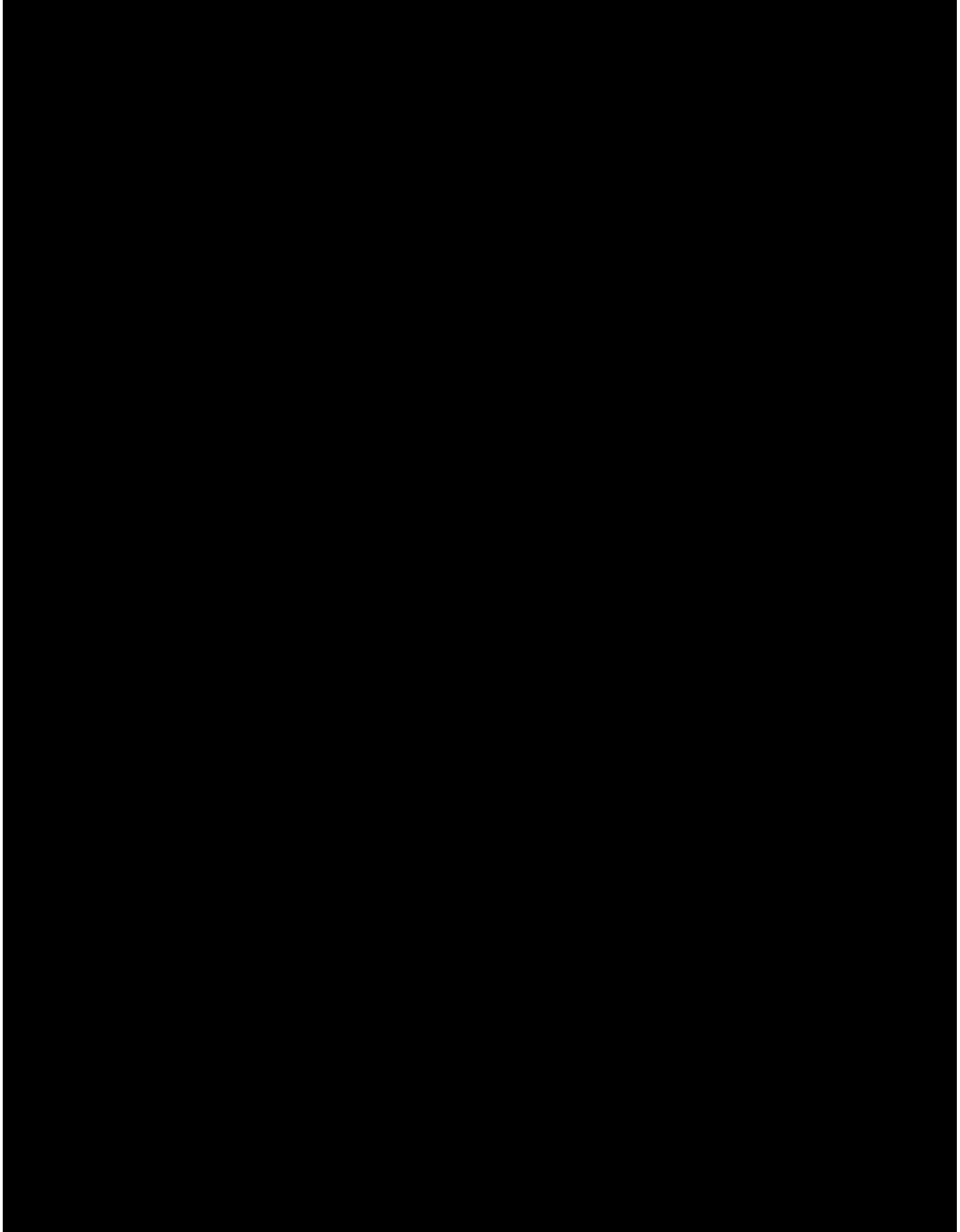
h) For LDC's that own and operate storage:

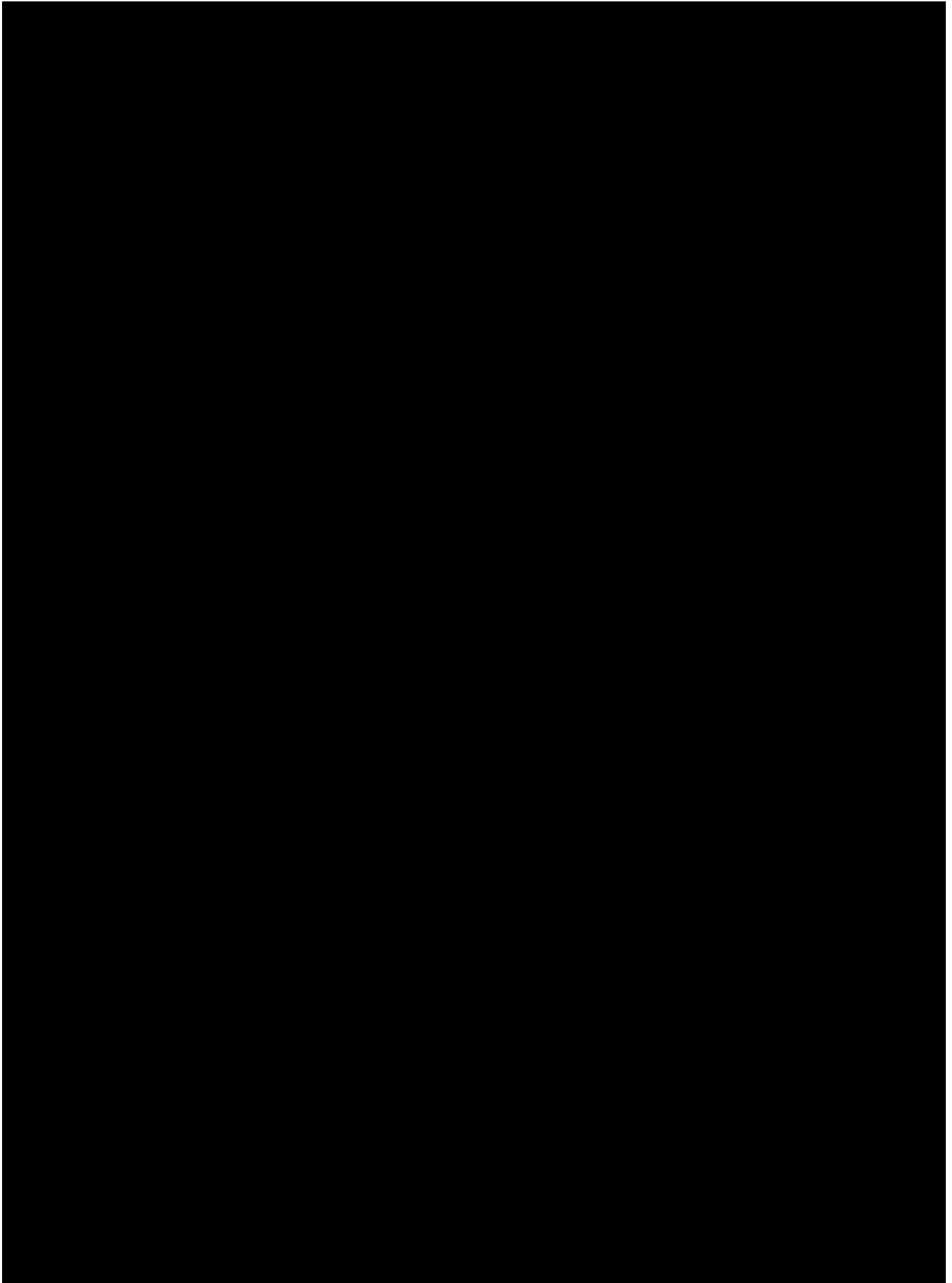
a. The date and results of the last engineering study for that storage.

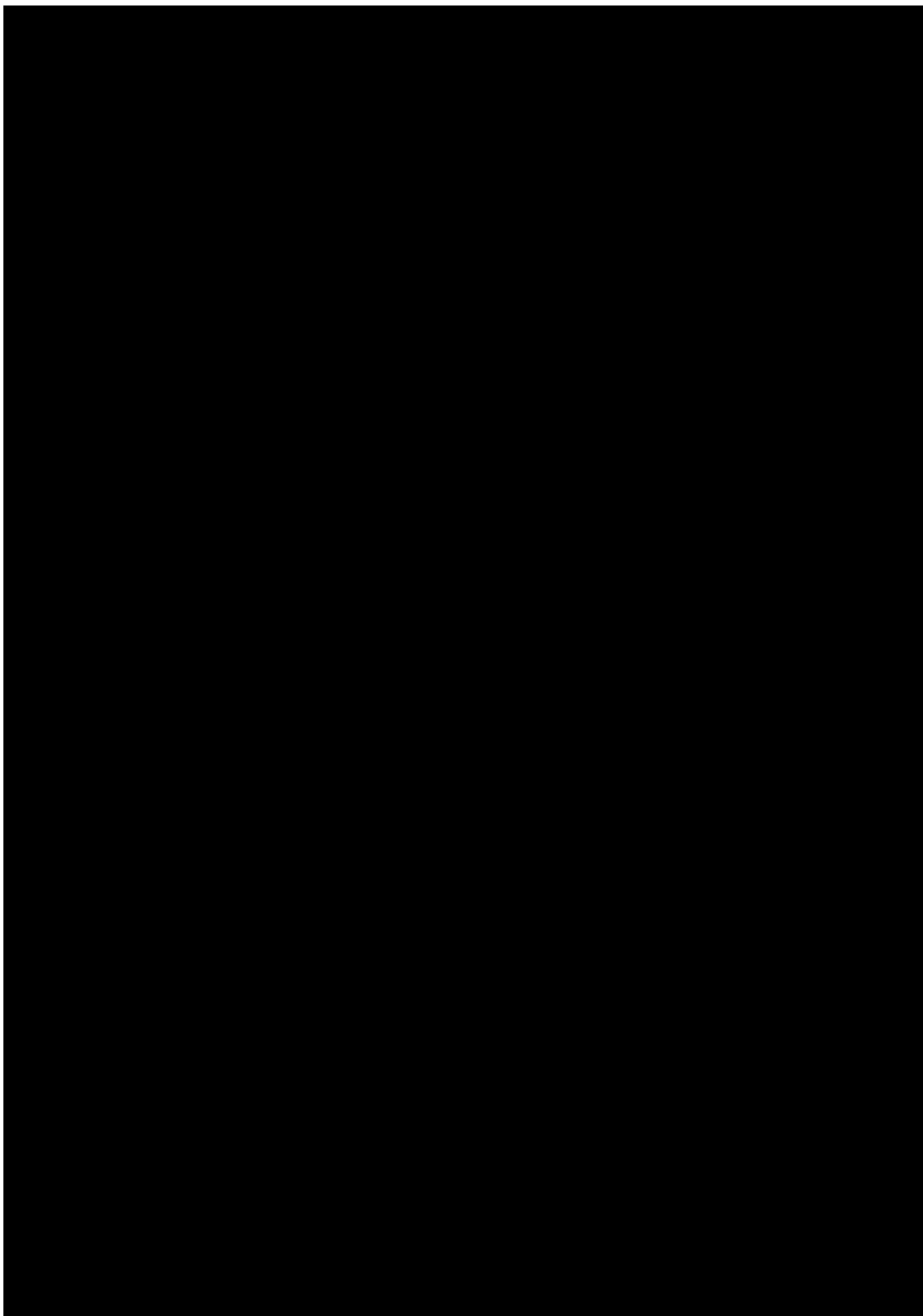
See Attachment 1 to V.7.h to this Exhibit C dated July 2017, identified as Confidential and subject to Modified Protective Order No. 10-337.

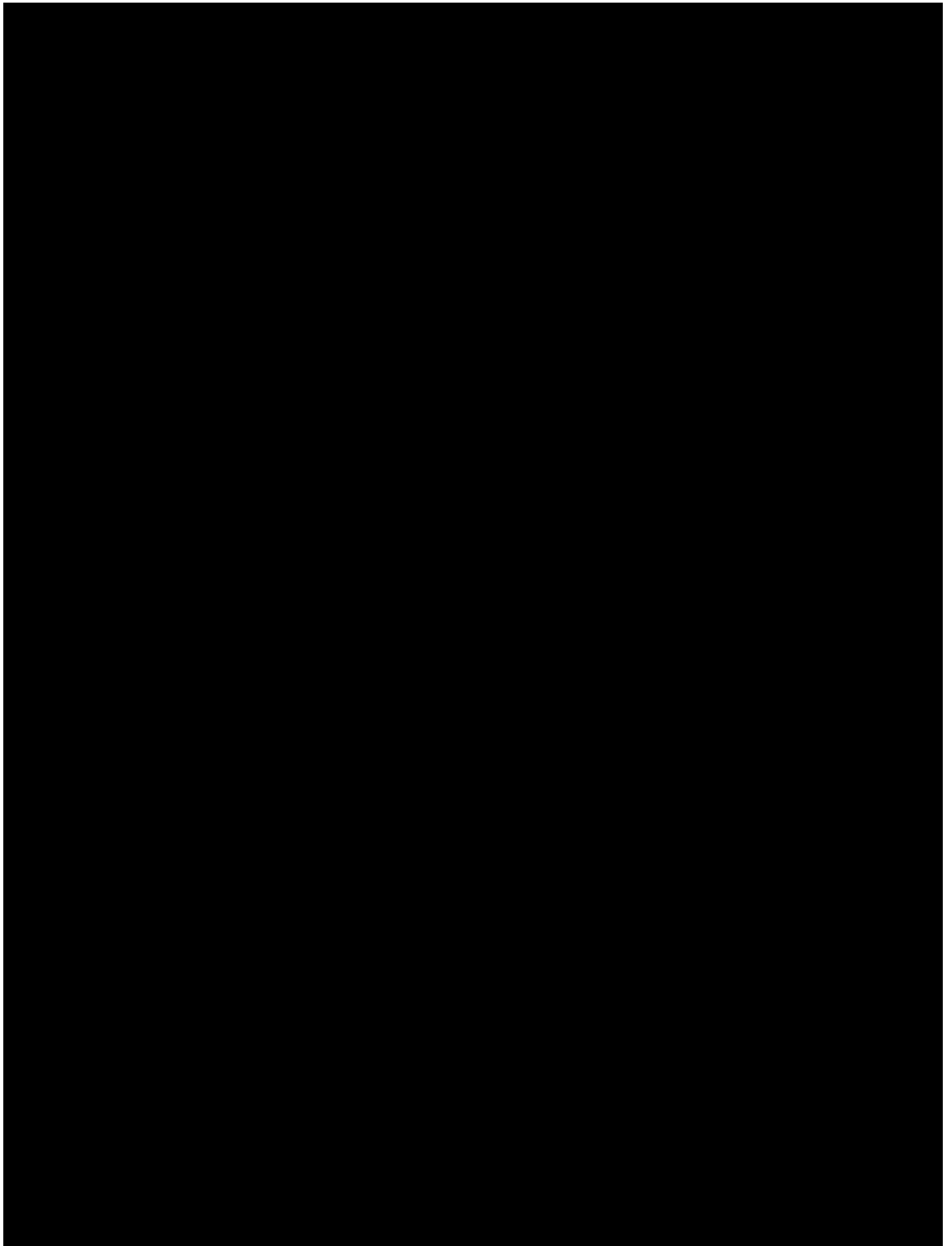
Confidential and subject to Modified Protective Order No. 10-337

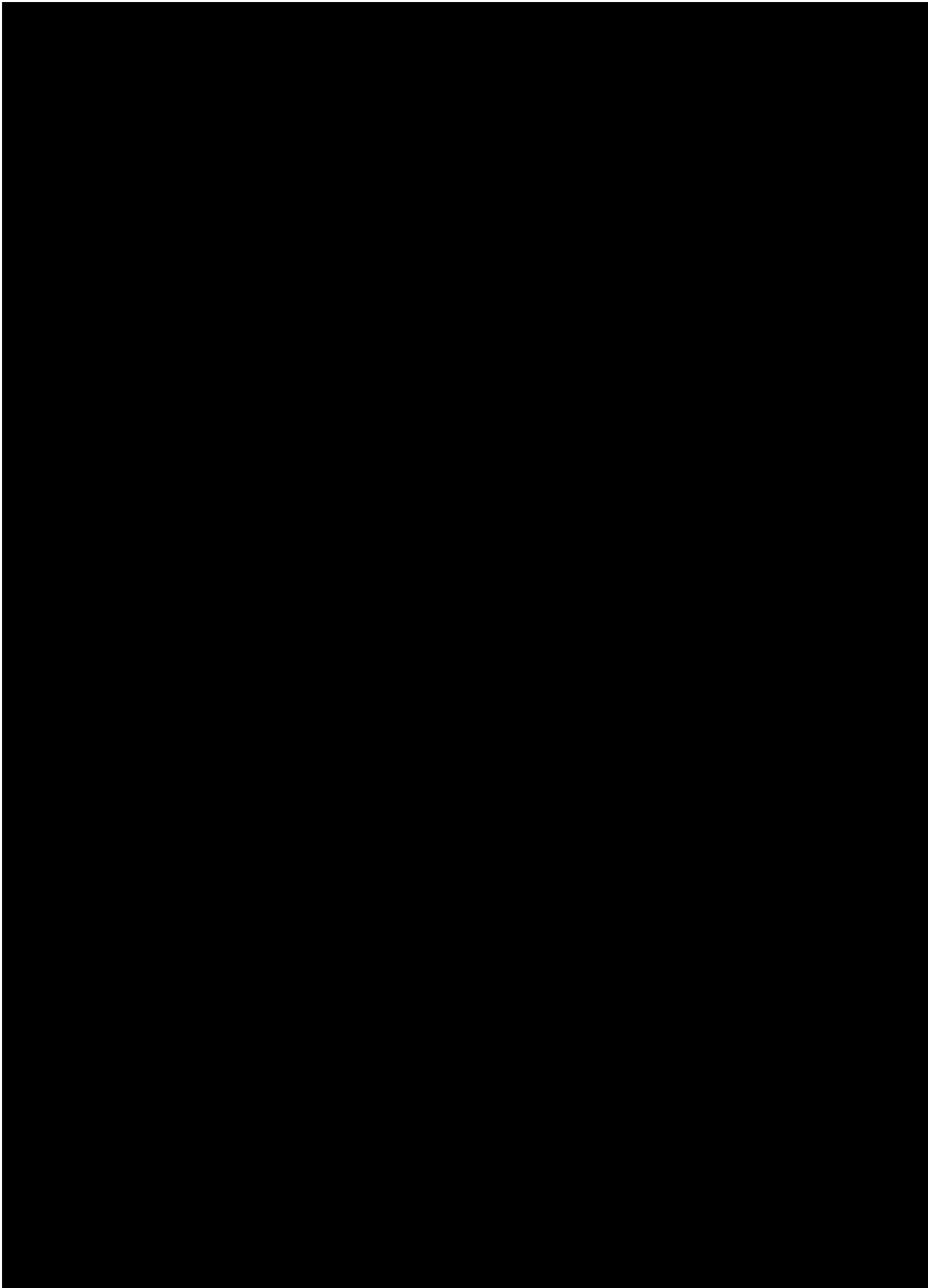


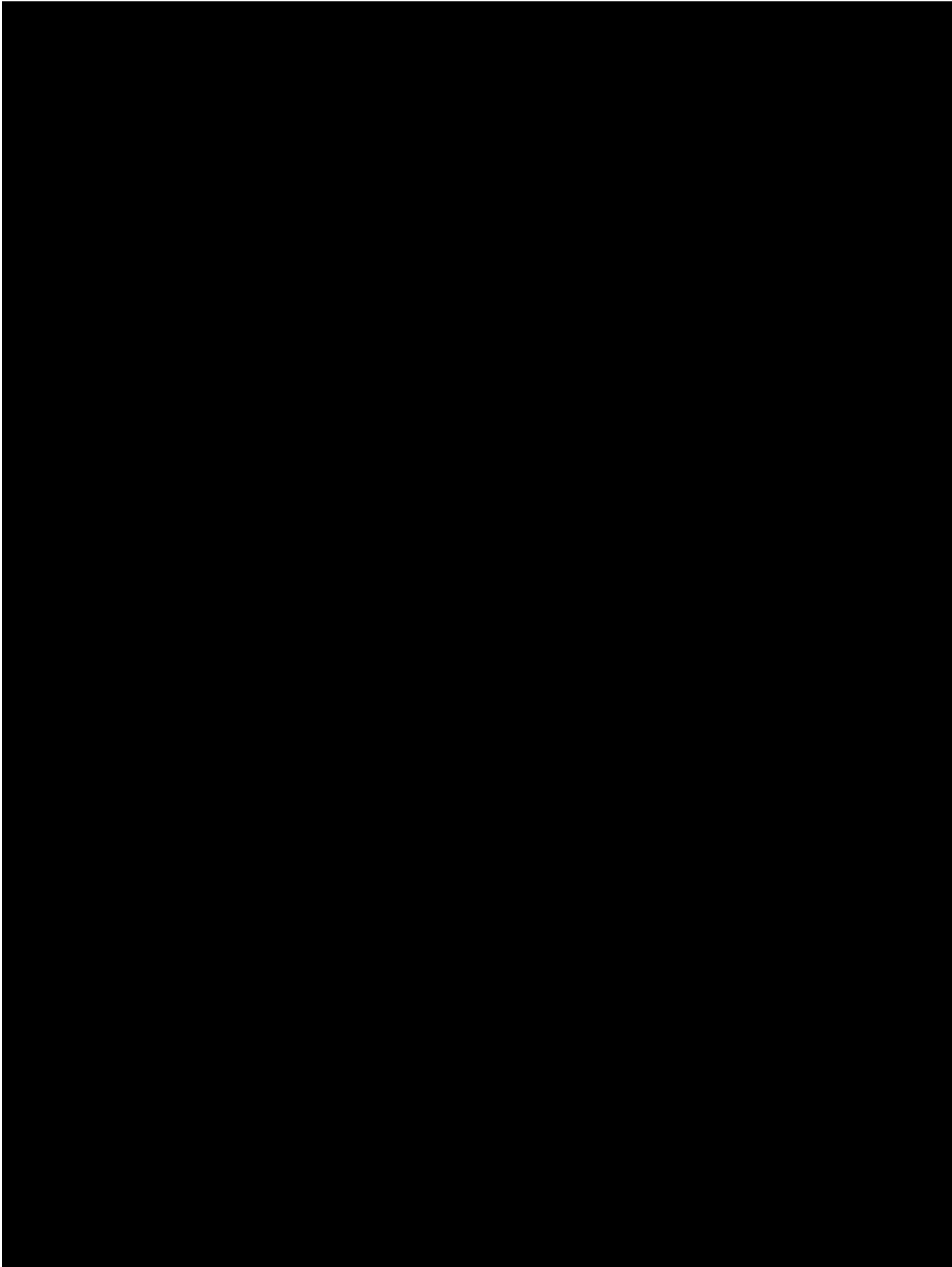


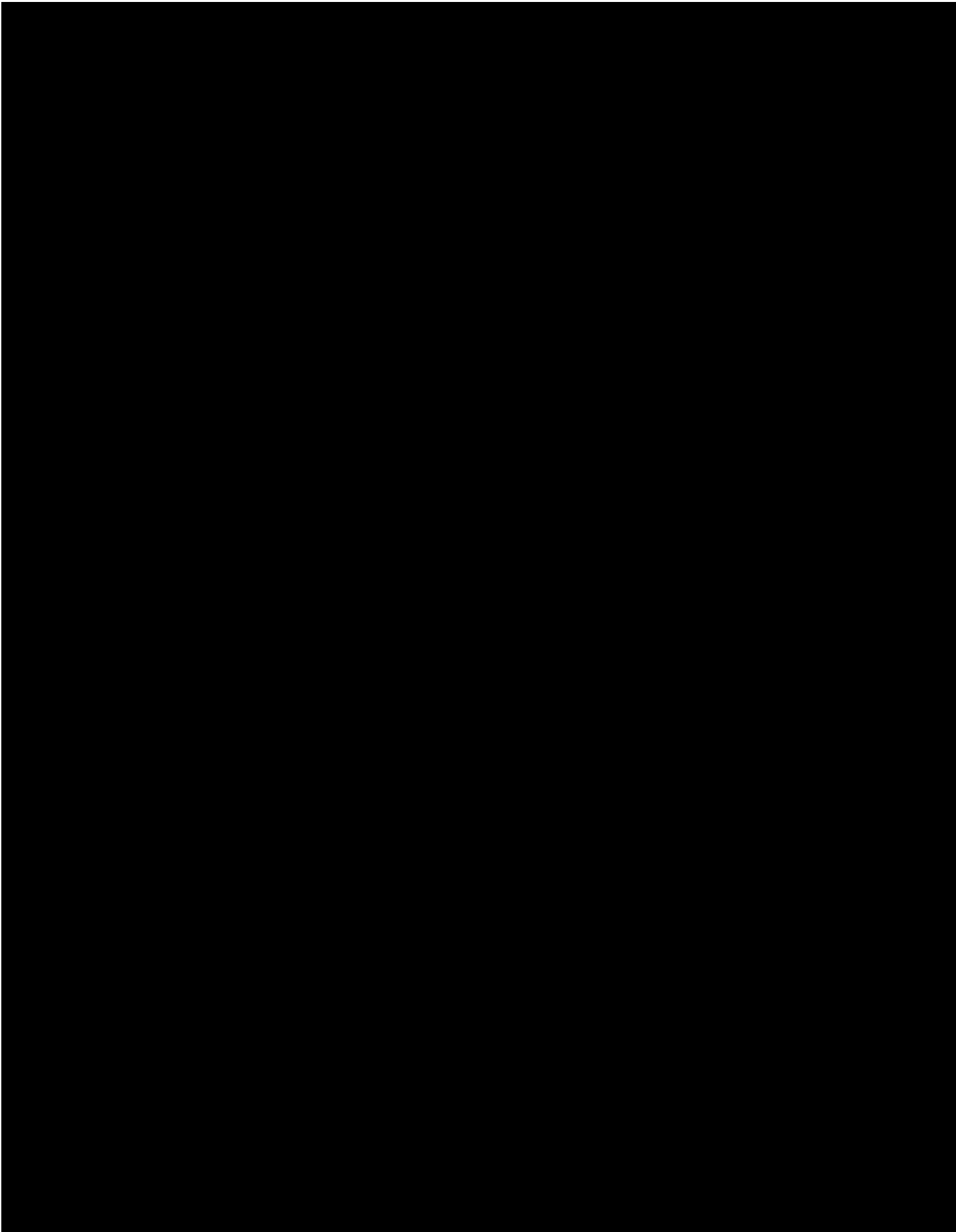


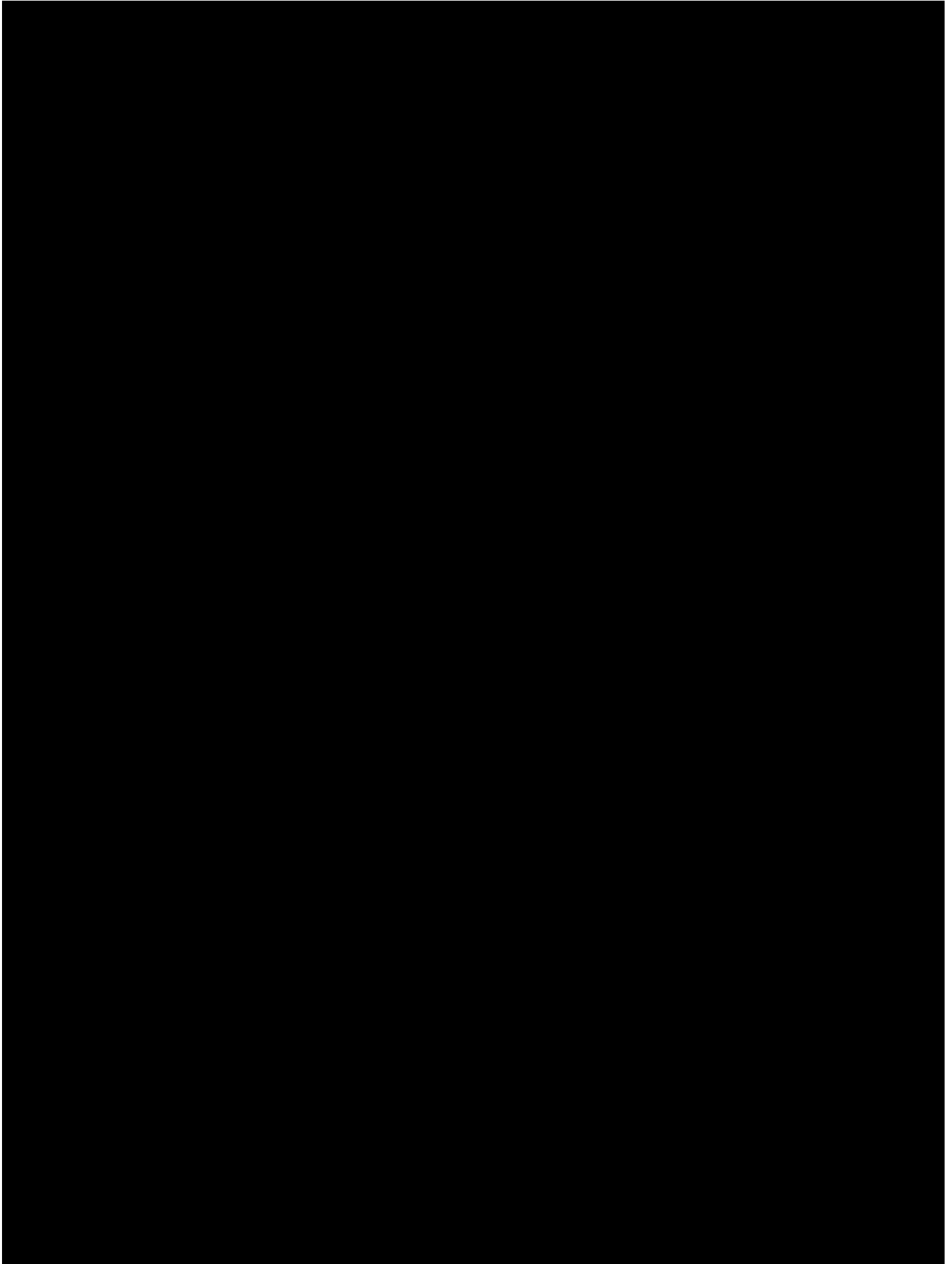


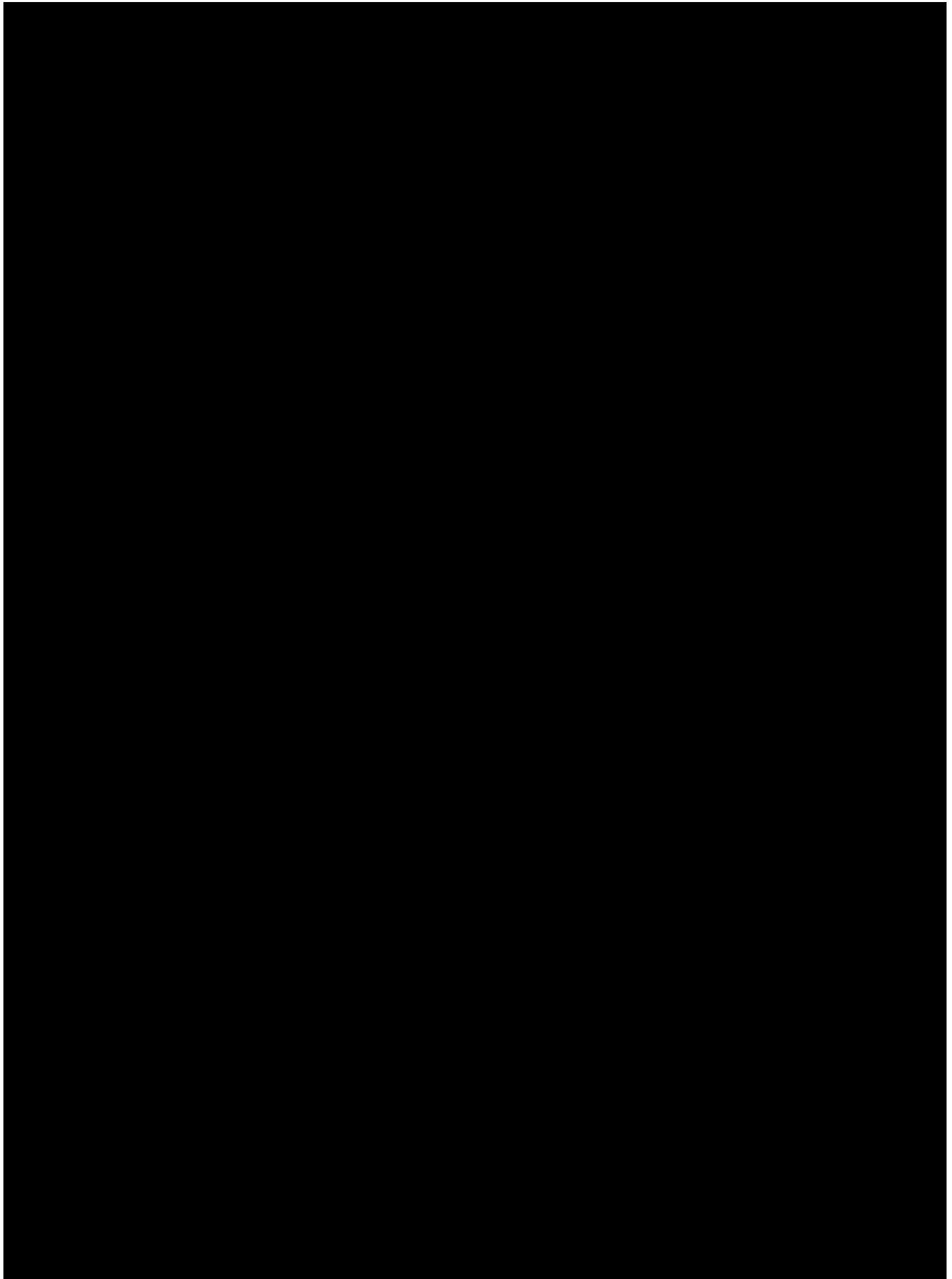


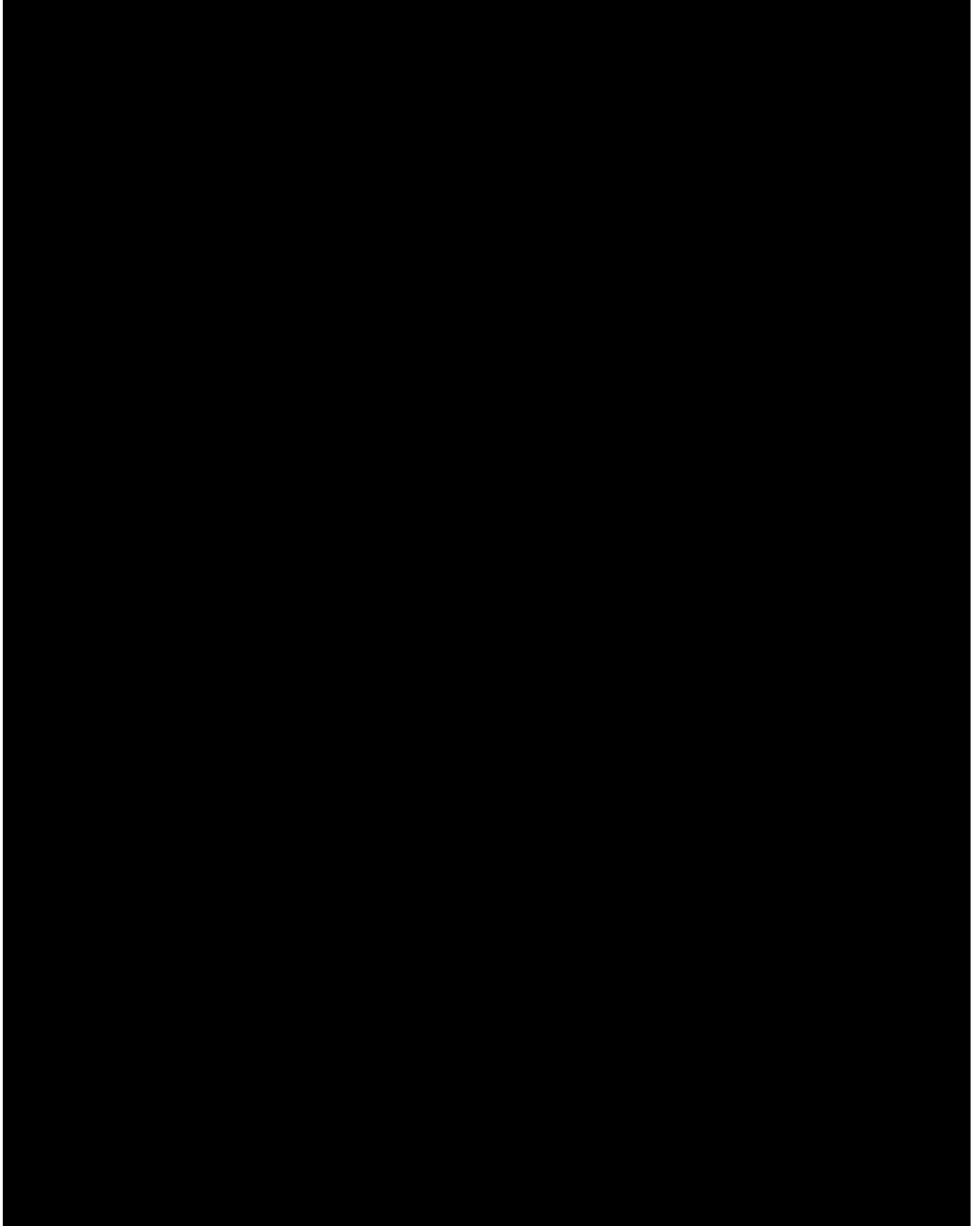


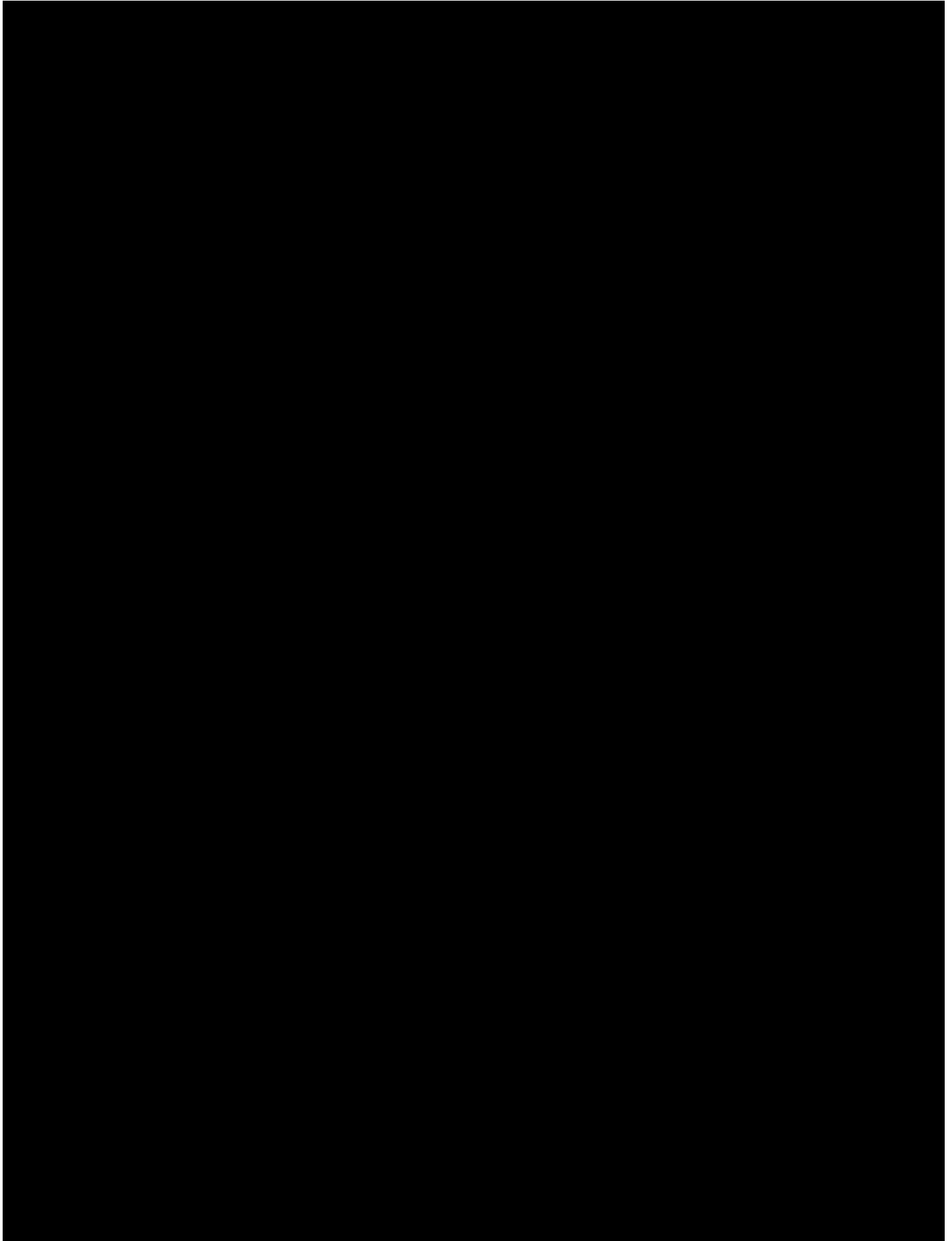


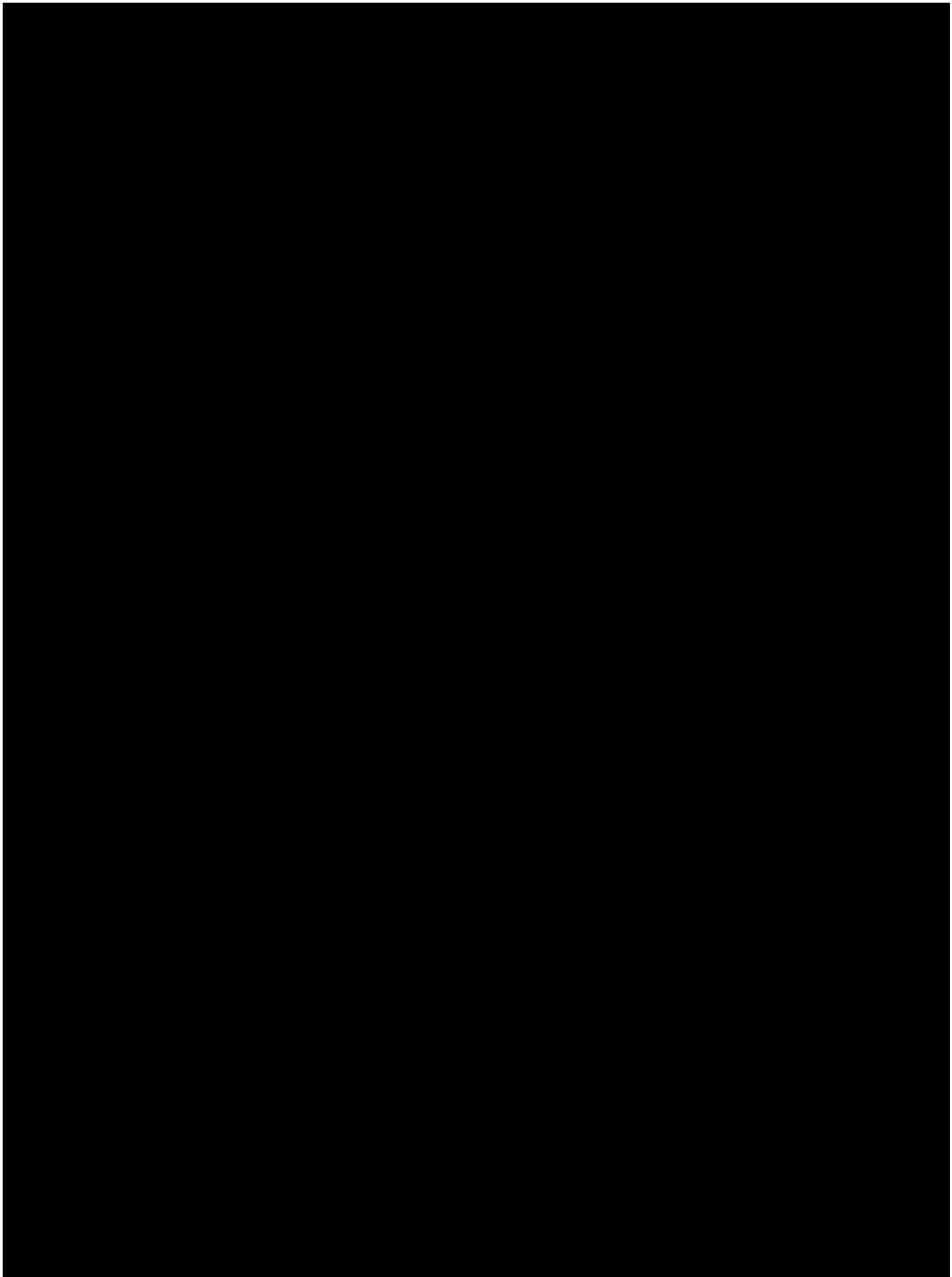


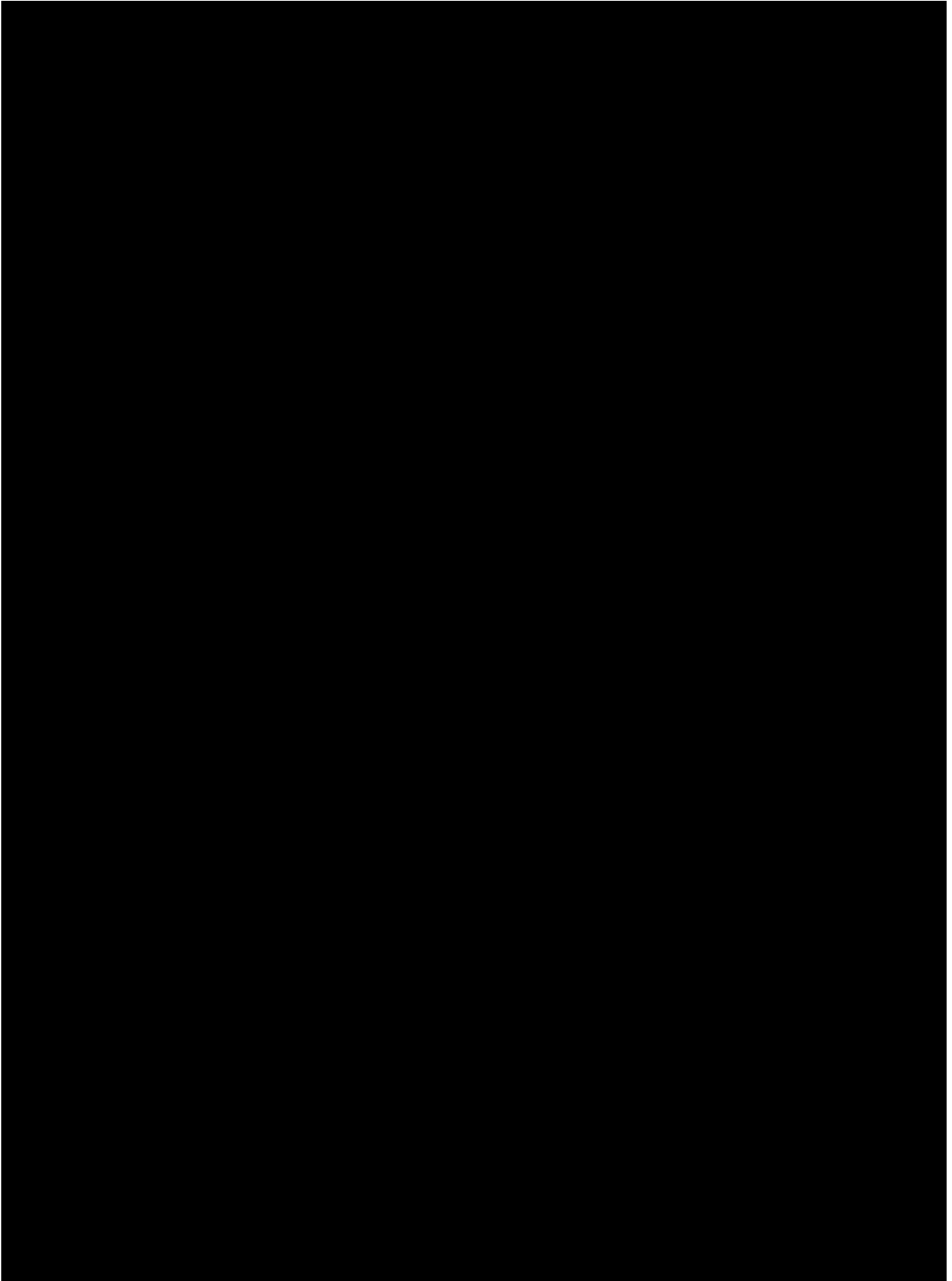












b. A description of any significant changes in physical or operational parameters of the storage facility (including LNG) since the current engineering study was completed.

There have been no significant changes in physical or operational parameters of the storage facility since completion of the July 2016 study.

Section V.8 - Attestation as to Consistency

See IV.1.c



CERTIFICATE OF SERVICE

I hereby certify that on July 28, 2017 I have served the foregoing unredacted version of the Confidential and Highly Confidential portions of NWN OPUC Advice No. 17-12 / UG 334 Exhibit C, subject to Modified Protective Order 10-337, via U.S. MAIL in Docket UM 1286.

Public Utility Commission of Oregon (C)(HC)
Attention: Filing Center
201 High Street SE, Suite 100
PO Box 1088
Salem, OR 97308-1088

Tommy A. Brooks (C)
Cable Huston Benedict Haagensen &
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Robert Jenks (C)(HC)
Citizens' Utility Board of Oregon
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Edward Finklea (C)(HC)
Northwest Industrial Gas Users
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Ashland, OR 97520

DATED at Portland, Oregon, this 28th day of July 2017.

/s/ Erica Lee
Erica Lee
Rates & Regulatory Affairs – Staff Assistant 3
NW NATURAL