

Rose Carbon Capture and Sequestration Project Injection Wells No. 01, No. 02, and No. 03

e e r u y e a

1

□ □ r □ □ □ □ □ □ □ □

☐

February 5

e d e e e a e r e a r R e r e e e e e a d

are a e r e u e e d r a r u u e r ed 5
year er d r de e da e e ary r de r a e da er e u der r u d
ur e dr a er D e e e u e e e d ab e by
Claimed as PBI a e e r a e u e r a red ed
be e a **Claimed as PBI** R u e R ee a u ur dur e a e a d
ure a e e r e e are ea ured u e ra ra e de
red ed ra ra e

Oeure de M. b's financial a...ura e de ...ra ...ea ...u d ...r ...e ...r ...e ...
 Oeure de M. b's financial a...ura e de ...ra ...ea ...u d ...r ...e ...r ...e ...
 Oeure de M. b's financial a...ura e de ...ra ...ea ...u d ...r ...e ...r ...e ...
 Oeure de M. b's financial a...ura e de ...ra ...ea ...u d ...r ...e ...r ...e ...
 Oeure de M. b's financial a...ura e de ...ra ...ea ...u d ...r ...e ...r ...e ...

[illegible]

□

Claimed as PBI

Claimed as PBI

MS D R S

er are r e a u e e

r r r	D M
°C	degrees Celsius
°F	degrees Fahrenheit
μD	microdarcy
μg/m ³	micrograms per meters cubed
μmhos/cm	micromhos per centimeter
in ² /lb	micro square inches per pound
2D	two-dimensional
3D	three-dimensional
ACS	American Community Survey
AMPP	Association for Materials Protection and Performance
AMSL	above mean sea level
AoR	Area of Review
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
AZMI	above-zone monitoring interval
BGL	measured depth below ground level
BHP	bottomhole pressure
BMSL	below mean sea level
BUQW	Base of Usable-Quality Water
CBG	Census Block Group
CBL	cement bond log
CCS	Carbon Capture and Storage
CEQ	U.S. Council on Environmental Quality
CFR	Code of Federal Regulations
CGM	Community Grievance Mechanism
CIL	casing inspection log
cm	centimeter
CO	carbon monoxide
CO ₂	carbon dioxide
COC	Chain-of-Custody
DHPT	downhole pressure temperature
DSA	double-studded adapter
DTS	distributed temperature sensing
EEHC	Exxon Equity Holding Company
EJ	environmental justice
EMC	Exxon Mobil Corporation
EOR	enhanced oil recovery

e d e a er a r R e r e e e e
a d

e d e e a er a r R e r e e e e
a d

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Requirement Matrix

The following requirements are for submittal of a Class VI Underground Injection Control application to the Railroad Commission of Texas. Additional submittals of the application to other regulatory agencies are indicated in this requirement matrix.

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.82	Required Class VI permit information		
146.91(e)	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	5.203(a)(1)(A) Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality. 5.207(b)(2) The operator must submit all required reports, submittals, and notifications under this subchapter to the director and to the EPA in an electronic format approved by the director and the Regional Administrator, respectively.	Class VI Application

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
Section 1 – Introduction			
146.82(a)(1)	Information required in 144.31(e)(1) through (6) of this chapter;	5.203(a)(2) General information. (A) On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility. (B) When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit. (C) The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs; (D) A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO2 injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued.	Section 1 – Introduction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
144.31(e)(8)	A brief description of the nature of the business.		Section 1.0 – Project Introduction
144.31(e)(1)	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	5.203(a)(2)(C) General information. The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	Section 1.15 – Permits and Construction Approvals for Rose CCS Project
146.82(a)(7)(iii)	The source(s) of the carbon dioxide stream; and	5.203(i)(1)(C) the sources of the CO2 stream and the volume and/or mass of CO2 from each source; and	Section 1.0 – Project Introduction and 1.8 Well Operations
146.82(a)(7)(iv)	An analysis of the chemical and physical characteristics of the carbon dioxide stream.	5.203(i)(1)(D) an analysis of the chemical and physical characteristics of the CO2 stream prior to injection.	1.8 Well Operations
144.31(e)(2)	Name, mailing address, and location of the facility for which the application is submitted.	5.203(a)(2)(A) General information. On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.	Section 1.2 – Contact Information
144.31(e)(3)	Up to four SIC codes which best reflect the principal products or services provided by the facility.	Not Addressed.	Section 1.2 – Contact Information

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
144.31(e)(4)	The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.	5.203(a)(2)(A) General information. On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility.	Section 1.2 – Contact Information
144.31(e)(5)	Whether the facility is located on Indian lands.	Refer to 5.203(a)(2)(E)and(F). 5.203(a)(2)(E) The application must indicate whether the geologic storage project is located on Indian lands. (F) The application must include a list of contacts for those States, Tribes, and Territories any portion of which is identified to be within the AOR of the geologic storage project based on the map showing the injection well and the AOR	Section 1.2 – Contact Information
144.31(e)(1)	The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination system (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.	5.203(a)(2)(C) General information. The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)	A listing of all permits or construction approvals received or applied for under any of the following programs:	5.203(a)(2)(C) General information. The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs;	Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)(i)	Hazardous Waste Management program under RCRA.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
144.31(e)(6)(ii)	UIC program under SDWA.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)(iii)	NPDES program under CWA.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)(iv)	Prevention of Significant Deterioration (PSD) program under the Clean Air Act.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)(v)	Nonattainment program under the Clean Air Act.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)(vi)	National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)(vii)	Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)(viii)	Dredge and fill permits under section 404 of CWA.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project
144.31(e)(6)(ix)	Other relevant environmental permits, including State permits.		Section 1.15 – Permits and Construction Approvals for Rose CCS Project

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section

Section 2 – Site Characterization			
146.82(a)(3)	Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:	5.203(c) Geologic, geochemical, and hydrologic information. (1) The applicant must submit a descriptive report prepared by a knowledgeable person that includes an interpretation of the results of appropriate logs, surveys, sampling, and testing sufficient to determine the depth, thickness, porosity, permeability, and lithology of, and the geochemistry of any formation fluids in, all relevant geologic formations. (2) The applicant must submit information on the geologic structure and reservoir properties of the proposed storage reservoir and overlying formations, including the following information:	Section 2.5 – Site Geology Section 2.9 – Assessment of Injection Interval and Confining Zone Geochemical Reactions Section 2.10 – Hydrogeology
146.82(a)(3)(ii)	The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	5.203(c)(2)(C) the location, orientation, and properties of known or suspected transmissive faults or fractures that may transect the confining zone within the AOR and a determination that such faults or fractures would not compromise containment;	Section 2.5.9 – Seismic Data
146.82(a)(3)(iii)	Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and	5.203(c)(2)(B) the depth, areal extent, thickness, mineralogy, porosity, permeability,	Section 2.3 – Major Stratigraphic Units:

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;	Confining and Injection Zones; Section 2.9 – Assessment of Injection Interval and Confining Zone Geochemical Reactions
146.82(a)(3)(iv)	Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	5.203(c)(2)(E) geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone;	Section 2.6 – Geomechanics and Petrophysics
146.82(a)(3)(v)	Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	5.203(c)(2)(D) the seismic history, including the presence and depth of seismic sources, and a determination that the seismicity would not compromise containment;	□ Section 2.11 – Seismic Risk and Fault-Slip Potential for AoR
146.82(a)(3)(vi)	Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	5.203(c)(2)(A) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	Appendix B

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.82(a)(5)	Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	5.203(c)(2)(A) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	Appendix B
146.82(a)(6)	Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	5.203(c)(2)(G) baseline geochemical data for subsurface formations that will be used for monitoring purposes, including all formations containing USDWs within the AOR.	Section 2.9 – Assessment of Injection Interval and Confining Zone Geochemical Reactions
146.83(a)	Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	5.206 (b) General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that: (6) the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include: (A) an injection zone of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the CO2 stream	Section 2.5.6. Geologic Characteristics of the Injection Zone; Section 2.12 Site Suitability
146.83(a)(1)	An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	5.206 (b) (6)(A) General criteria. The director may issue a permit under this subchapter if the applicant demonstrates and the director finds that: (6) the geologic storage facility will be sited in an area with suitable geology, which at a minimum must include: (A) an injection zone of sufficient areal extent, thickness, porosity,	Section 2.5.6. Geologic Characteristics of the Injection Zone; Section 2.12 Site Suitability

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		and permeability to receive the total anticipated volume of the CO2 stream;	
146.83(a)(2)	Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	5.206 (b) (6)(B) a confining zone that is laterally continuous and free of known transecting transmissive faults or fractures over an area sufficient to contain the injected CO2 stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without compromising the confining zone or causing the movement of fluids that endangers USDWs	Section 2.3 – Major Stratigraphic Units: Confining and Injection Zones; Section 2.9 – Assessment of Injection Interval and Confining Zone Geochemical Reactions; Section 2.5.5 – Top and Bottom Elevations of Injection and Confining Zones
146.83(b)	The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.		Not Applicable
146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	5.203(d) (1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	Section 3.9 Corrective Action Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	5.203(d)(1)(A) (i) Delineation of AOR. (i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods: (I) five years after initiation of injection; (II) from initiation of injection to the end of the injection period proposed by the applicant; and (III) from initiation of injection until the movement of the CO2 plume and associated pressure front stabilizes.	Section 2.8.1 Geologic Model of the AoR Appendix B
146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	5.203(d)(1)(A) (ii) (I) and (II) (ii) The applicant must use a computational model that: (I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; (II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	Section 2.1 – Reservoir Characterization and 3D Geologic Modeling

Section 3 – AoR and Corrective Action			
146.84(a)	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site	5.102(5) Area of review (AOR)--The subsurface three dimensional extent of the CO2 stream plume and the associated pressure front, as well as the overlying formations, any underground sources of drinking water overlying an injection zone along with any intervening formations, and	Sections 3.3, 3.4, 3.5, 3.6, and 3.7

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	characterization, monitoring, and operational data.	the surface area above that delineated region.	
146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	5.203(d) (1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	Section 3.7 – AoR Delineation Based on Model Results Section 3.9 – Corrective Action Plan and Schedule
146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	5.203(d)(1)(A) (i) Delineation of AOR. (i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods: (I) five years after initiation of injection; (II) from initiation of injection to the end of the injection period proposed by the applicant; and (III) from initiation of injection until the movement of the CO2 plume and associated pressure front stabilizes.	Section 3.7 – AoR Delineation Based on Model Results Section 3.10 – AoR Reevaluation Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	5.203(d)(1)(A) (ii) (I) and (II) (ii) The applicant must use a computational model that: (I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; (II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	Sections 3.3, 3.4, 3.5, 3.6, and 3.7
146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	5.203(d)(1)(A) (ii) (III) (ii) The applicant must use a computational model that: (III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions;	Section 3.8 – Model Calibration and Validation
146.93(c)(1)(iii)	The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;	5.203(m)(7)(C) the predicted rate of CO2 plume migration within the injection zone, and the predicted timeframe for the stabilization of the CO2 plume and associated pressure front;	Section 3.7 – AoR Delineation Based on Model Results
146.93(c)(1)(iv)	A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	5.203(m)(7)(D) a description of the site-specific processes that will result in CO2 trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;	Section 3.6 – Model Design and Input Parameters
146.93(c)(1)(v)	The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	5.203(m)(7)(E) the predicted rate of CO2 trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;	Section 3.6 – Model Design and Input Parameters
146.82(a)(7)(ii)	Average and maximum injection pressure;	5.203(i)(1)(B) the average and maximum surface injection pressure;	Section 3.6.3 – Fluid Injection Rates

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.82(a)(1)	Information required in 144.31(e)(1) through (6) of this chapter;	5.203(a)(2) General information. (A) On the application, the applicant must include the name, mailing address, and location of the facility for which the application is being submitted and the operator's name, address, telephone number, Commission Organization Report number, and ownership of the facility. (B) When a geologic storage facility is owned by one person but is operated by another person, it is the operator's duty to file an application for a permit. (C) The application must include a listing of all required permits or construction approvals for the facility received or applied for under federal or state environmental programs; (D) A person making an application to the director for a permit under this subchapter must submit a copy of the application to the Texas Commission on Environmental Quality (TCEQ) and must submit to the director a letter of determination from TCEQ concluding that drilling and operating an anthropogenic CO₂ injection well for geologic storage or constructing or operating a geologic storage facility will not impact or interfere with any previous or existing Class I injection well, including any associated waste plume, or any other injection well authorized or permitted by TCEQ. The letter must be submitted to the director before any permit under this subchapter may be issued. (E) The application must indicate whether the geologic storage project is located on Indian lands. (F) The	Section 1 – Introduction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		application must include a list of contacts for those States, Tribes, and Territories any portion of which is identified to be within the AOR of the geologic storage project based on the map showing the injection well and the AOR.	
146.82(a)(2)	A map showing the injection well for which a permit is sought and the applicable area of review consistent with 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	5.203 (b) Surface map and information. Only information of public record is required to be included on this map. (1) The applicant must file with the director a surface map delineating the proposed location and geographic coordinates of any injection wells, any proposed monitoring wells, and the boundary of the geologic storage facility for which a permit is sought and the applicable AOR. The applicant must indicate the coordinate system used. (2) The applicant must show within the AOR on the map the number or name and the location of: (A) all known artificial penetrations through the confining zone, including stratigraphic boreholes, injection wells, producing wells, inactive wells, plugged wells, or dry holes; (B) the locations of cathodic protection holes, subsurface cleanup sites, bodies of surface water, springs, surface and subsurface mines, quarries, and water wells; and (C) other pertinent surface features, including pipelines, roads, and structures intended for human occupancy. (3) The applicant must identify on the map any known or suspected faults expressed at the surface.	Appendix B – Site Characterization Files

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.82(a)(3)(i)	Maps and cross sections of the area of review;	5.203(c)(2)(A) geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the area from the ground surface to the base of the injection zone within the AOR that indicate the general vertical and lateral limits of all USDWs within the AOR, their positions relative to the storage reservoir and the direction of water movement, where known;	Appendix B – Site Characterization Files
146.82(a)(4)	A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	5.203(d)(1)(B) Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each penetration's type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties	Section 3.9 – Corrective Action Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.82(a)(13)	Proposed area of review and corrective action plan that meets the requirements under 146.84;	5.203(d)(2) AOR and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information: (A) the method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based; (B) for the AOR, a description of: (i) the minimum fixed frequency, not to exceed five years, at which the applicant proposes to reevaluate the AOR during the life of the geologic storage facility; (ii) how monitoring and operational data will be used to re-evaluate the AOR; and (iii) the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and (C) a corrective action plan that describes: (i) how the corrective action will be conducted; (ii) how corrective action will be adjusted if there are changes in the AOR; (iii) if a phased corrective action is planned, how the phasing will be determined; and (iv) how site access will be secured for future corrective action.	Section 3.9 – Corrective Action Plan and Schedule
146.82(a)(20)	A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and		Section 1 – Introduction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.84(a)	The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	5.102(5) Area of review (AOR)--The subsurface three dimensional extent of the CO2 stream plume and the associated pressure front, as well as the overlying formations, any underground sources of drinking water overlying an injection zone along with any intervening formations, and the surface area above that delineated region.	Sections 3.3, 3.4, 3.5, 3.6, and 3.7
146.84(b)	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	5.203(d) AOR and corrective action. This subsection describes the standards for the information regarding the delineation of the AOR, the identification of penetrations, and corrective action that an applicant must include in an application. (1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased. (A) Delineation of AOR. (i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the	Sections 3.3, 3.4, 3.5, 3.6, 3.7, and 3.9

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods: (I) five years after initiation of injection; (II) from initiation of injection to the end of the injection period proposed by the applicant; and (III) from initiation of injection until the movement of the CO2 plume and associated pressure front stabilizes. (ii) The applicant must use a computational model that: (I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; (II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection; (III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions; (IV) considers the physical and chemical properties of injected and formation fluids; and (V) considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points. (iii) The applicant must provide the name and a description of the model, software, the assumptions used to determine the AOR, and the equations solved.	

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.84(b)(1)	The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	5.203(d)(2) (A) AOR and corrective action plan. As part of an application, the applicant must submit an AOR and corrective action plan that includes the following information: (A) the method for delineating the AOR, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	Sections 3.3, 3.4, 3.5, 3.6, and 3.7
146.84(b)(2)	A description of:	5.203(d)(2)(B) for the AOR, a description of:	See Below
146.84(b)(2)(i)	The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	5.203(d)(2)(B)(i) the minimum fixed frequency, not to exceed five years, at which the applicant proposes to reevaluate the AOR during the life of the geologic storage facility;	Section 3.10 – AoR Reevaluation Plan and Schedule
146.84(b)(2)(ii)	The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	5.203(d)(2)(B)(iii) the monitoring and operational conditions that would warrant a re-evaluation of the AOR prior to the next scheduled re-evaluation; and	Section 3.10 – AoR Reevaluation Plan and Schedule
146.84(b)(2)(iii)	How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	5.203(d)(2)(B)(ii) how monitoring and operational data will be used to re-evaluate the AOR;	Section 3.10 – AoR Reevaluation Plan and Schedule
146.84(b)(2)(iv)	How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are	5.203(d)(2)(C) a corrective action plan that describes: (i) how the corrective action will be conducted; (ii) how corrective action will be adjusted if there are changes in the AOR; (iii) if a phased corrective action is planned, how the phasing will be determined; and	Section 3.9 – Corrective Action Plan and Schedule Section 3.10 – AoR Reevaluation Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	changes in the area of review; and how site access will be guaranteed for future corrective action.	(iv) how site access will be secured for future corrective action.	
146.84(c)	Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:	5.203(d)(1) Initial delineation of the AOR and initial corrective action. The applicant must delineate the AOR, identify all wells that require corrective action, and perform corrective action on those wells. Corrective action may be phased.	See Below
146.84(c)(1)	Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	5.203(d)(1)(A) (i) Delineation of AOR. (i) Using computational modeling that considers the volumes and/or mass and the physical and chemical properties of the injected CO2 stream, the physical properties of the formation into which the CO2 stream is to be injected, and available data including data available from logging, testing, or operation of wells, the applicant must predict the lateral and vertical extent of migration for the CO2 plume and formation fluids and the pressure differentials required to cause movement of injected fluids or formation fluids into a USDW in the subsurface for the following time periods: (I) five years after initiation of injection; (II) from initiation of injection to the end of the injection period proposed by the applicant; and (III) from initiation of injection until the movement of the CO2 plume and associated pressure front stabilizes.	Section 3.7 – AoR Delineation Based on Model Results Appendix B

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.84(c)(1)(i)	Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	5.203(d)(1)(A) (ii) (I) and (II) (ii) The applicant must use a computational model that: (I) is based on geologic and reservoir engineering information collected to characterize the injection zone and the confining zone; (II) is based on anticipated operating data, including injection pressures, rates, temperatures, and total volumes and/or mass over the proposed duration of injection;	Sections 3.3, 3.4, 3.5, 3.6, and 3.7
146.84(c)(1)(ii)	Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	5.203(d)(1)(A) (ii) (III) (ii) The applicant must use a computational model that: (III) takes into account relevant geologic heterogeneities and data quality, and their possible impact on model predictions;	3.6 Model Design and Input Parameters
146.84(c)(1)(iii)	Consider potential migration through faults, fractures, and artificial penetrations	5.203(d)(1)(A) (ii) (V) (V) considers potential migration through known faults, fractures, and artificial penetrations and beyond lateral spill points.	Section 3.6.4 – Fracture Pressure and Fracture Gradient Section 3.9 – Corrective Action Plan and Schedule
146.84(c)(2)	Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	5.203(d)(1)(B) Identification and table of penetrations. The applicant must identify, compile, and submit a table listing all penetrations, including active, inactive, plugged, and unplugged wells and underground mines in the AOR that may penetrate the confining zone, that are known or reasonably discoverable through specialized knowledge or experience. The applicant must provide a description of each	Section 3.9 – Corrective Action Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		penetration's type, construction, date drilled or excavated, location, depth, and record of plugging and/or completion or closure. Examples of specialized knowledge or experience may include reviews of federal, state, and local government records, interviews with past and present owners, operators, and occupants, reviews of historical information (including aerial photographs, chain of title documents, and land use records), and visual inspections of the facility and adjoining properties.	
146.84(c)(3)	Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	5.203(d)(1)(C) Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The demonstration shall include evidence that the materials used are compatible with the carbon dioxide stream. The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO2 stream. Corrective action may be phased	Section 3.9 – Corrective Action Plan and Schedule

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.84(d)	Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	5.203(d)(1)(C) Corrective action. The applicant must demonstrate whether each of the wells on the table of penetrations has or has not been plugged and whether each of the underground mines (if any) on the table of penetrations has or has not been closed in a manner that prevents the movement of injected fluids or displaced formation fluids that may endanger USDWs or allow the injected fluids or formation fluids to escape the permitted injection zone. The demonstration shall include evidence that the materials used are compatible with the carbon dioxide stream. The applicant must perform corrective action on all wells and underground mines in the AOR that are determined to need corrective action. The operator must perform corrective action using materials suitable for use with the CO2 stream. Corrective action may be phased	Section 3.9 – Corrective Action Plan and Schedule
146.84(e)	At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	5.206(g) Permit conditions for AOR and corrective action. At the frequency specified in the approved AOR and corrective action plan or permit, and whenever warranted by a material change in the monitoring and/or operational data or in the evaluation of the monitoring and operational data by the operator, but no less frequently than every five years, the operator of a geologic storage facility also must:	See Below
146.84(e)(1)	Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;	5.206(g) (1) perform a re-evaluation of the AOR by performing all of the actions specified in 5.203(d)(1)(A) – (C) of this title to delineate	3.10 – AoR Reevaluation Plan and Schedule

Section 4 – Engineering Design and Operations

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.82(c)(5)	Final injection well construction procedures that meet the requirements of 146.86;	5.206(c) Permit conditions for injection well construction. (1) Construction of anthropogenic CO2 injection wells must meet the criteria in 5.203(e) of this title. (2) Within 30 days after the completion or conversion of an injection well subject to this subchapter, the operator must file with the division a complete record of the well on Commission Form W-2, Oil Well Potential Test, Completion or Recompletion Report and Log showing the current completion. (3) Except in the case of an emergency repair, the operator of a geologic storage facility must notify the director in writing at least 30 days prior to conducting any well workover that involves running tubing and setting packers, beginning any workover or remedial operation, or conducting any required pressure tests or surveys. Such activities shall not commence before the end of the 30 days unless authorized by the director. In the case of an emergency repair, the operator must notify the director of such emergency repair as soon as reasonably practical	Section 4.0 – Well Construction Plan and Operating Conditions
146.86	Injection well construction requirements.	5.203(e)Injection well construction.	Section 4.0 – Well Construction Plan and Operating Conditions
146.86(a)	General. The owner or operator must ensure that all Class VI wells are constructed and completed to:	5.203(e)(1)(A) General. The operator of a geologic storage facility must ensure that all anthropogenic CO2 injection wells are constructed and completed in a manner that will:	See Below

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.86(a)(1)	Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	5.203(e)(1)(A)(i) prevent the movement of injected CO2 or displaced formation fluids into any unauthorized zones or into any areas where they could endanger USDWs;	Section 4.1 – Objectives, Section 4.2 – Engineering Design
146.86(a)(2)	Permit the use of appropriate testing devices and workover tools; and	5.203(e)(1)(A)(ii) allow the use of appropriate testing devices and workover tools; and	Section 4.1 – Objectives, Section 4.2 – Engineering Design
146.86(a)(3)	Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	5.203(e)(1)(A)(iii) allow continuous monitoring of the annulus space between the injection tubing and long string casing	Section 4.1 – Objectives, Section 4.2 – Engineering Design
146.86(b)	Casing and cementing of Class VI wells.	5.203(e)(1)(B) Casing and cementing of anthropogenic CO2 injection wells.	See Below

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.86(b)(1)	Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	5.203(e)(1)(B)(i) The operator must ensure that injection wells are cased and the casing cemented in compliance with 3.13 of this title (relating to Casing, Cementing, Drilling, Well Control, and Completion Requirements), in addition to the requirements of this section. 5.203(e)(1)(B)(ii) Casing, cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed test standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards as approved by the director. 5.203(e)(2) Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:	Section 4.1 – Objectives Section 4.2 – Engineering Design
146.86(b)(1)(i)	Depth to the injection zone(s);	5.203(e)(2)(A) depth to the injection zone;	Section 4.3.4 – Injection Well Completion Stage and Injection Interval, Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.86(b)(1)(ii)	Injection pressure, external pressure, internal pressure, and axial loading;	5.203(e)(2)(D) proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, external pressure, internal pressure, axial loading, and maximum proposed volume and/or mass of the CO2 stream to be injected;	Section 4.5 – Injection Well Operating Strategy, Appendix D
146.86(b)(1)(iii)	Hole size;	5.203(e)(2)(B) hole size;	Section 4.3 – Well Drilling and Completion Design, Appendix D
146.86(b)(1)(iv)	Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);	5.203(e)(2)(C) size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths);	Section 4.2 – Engineering Design, Appendix D
146.86(b)(1)(v)	Corrosiveness of the carbon dioxide stream and formation fluids;	5.203(e)(2)(F) a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO2 stream and formation fluids;	Section 4.2 – Engineering Design Appendix D
146.86(b)(1)(vi)	Down-hole temperatures;	5.203(e)(2)(G) down-hole temperatures and pressures;	4.4.4 Fracture Pressure, Fluid Characteristics, and Downhole Conditions
146.86(b)(1)(vii)	Lithology of injection and confining zone(s);	5.203(e)(2)(H) lithology of injection and confining zones;	Section 2.3 – Major Stratigraphic Units: Confining and Injection Zones Section 2.5 – Site Geology
146.86(b)(1)(viii)	Type or grade of cement and cement additives; and	5.203(e)(2)(I) type or grade of cement and additives;	4.2.2 Production Casing Design and Completion
146.86(b)(1)(ix)	Quantity, chemical composition, and temperature of the carbon dioxide stream.	5.203(e)(2)(J) chemical composition and temperature of the CO2 stream;	Section 1 – Introduction Section 4.5.5 – CO2 Stream Characteristics

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.86(b)(2)	Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	5.203(e)(1)(B)(iii) Surface casing must extend through the base of the lowermost USDW above the injection zone and must be cemented to the surface.	Section 4.2.2 – Production Casing Design and Completion, Appendix D
146.86(b)(3)	At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	5.203(e)(1)(B)(v) At least one long string casing, using a sufficient number of centralizers, must extend from the surface to the injection zone and must be cemented by circulating cement to the surface in one or more stages. The long string casing must isolate the injection zone and other intervals as necessary for the protection of USDWs and to ensure confinement of the injected and formation fluids to the permitted injection zone using cement and/or other isolation techniques. If the long string casing does not extend through the injection zone, another well string or liner must be cemented through the injection zone (for example, a chrome liner).	Section 4.2.2 – Production Casing Design and Completion, Appendix D
146.86(b)(4)	Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	5.203(e)(1)(B)(iv) Circulation of cement may be accomplished by staging. The director may approve an alternative method of cementing in cases where the cement cannot be circulated to the surface, provided the applicant can demonstrate by using logs that the cement does not allow fluid movement between the casing and the well bore.	Section 4.2.2 – Production Casing Design and Completion, Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.86(b)(5)	Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	5.203(e)(1)(B)(ii) Casing, cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed test standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards as approved by the director. 5.203(e)(1)(B)(vi) The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered.	Section 4.1 – Objectives Section 4.2 – Engineering Design
146.86(c)	Tubing and packer.		Section 4.2.3 – Injection Tubing Design and Completion Section 4.2.6 – Injection Tubing Packer Design and Completion

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.86(c)(1)	Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	5.203(e)(1)(B)(ii)Casing, cement, cement additives, and/or other materials used in the construction of each injection well must have sufficient structural strength and must be of sufficient quality and quantity to maintain integrity over the design life of the injection well. All well materials must be suitable for use with fluids with which the well materials may be expected to come into contact and must meet or exceed test standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards as approved by the director.	Section 4.1 – Objectives Section 4.2.3 – Injection Tubing Design and Completion Section 4.2.6 – Injection Tubing Packer Design and Completion
146.86(c)(2)	All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director	5.203(e)(1)(C)(i)Tubing and packer. All injection wells must inject fluids through tubing set on a packer. Packers must be set no higher than 100 feet above the top of the permitted injection interval or at a location approved by the director.	Section 4.2.3 – Injection Tubing Design and Completion Section 4.2.6 – Injection Tubing Packer Design and Completion
146.86(c)(3)	In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	5.203(e)(2)Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection:	See Below
146.86(c)(3)(i)	Depth of setting;	5.203(e)(2)(E) type of packer and packer setting depth;	Section 4.2.3 – Injection Tubing Design and Completion, Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.86(c)(3)(ii)	Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;	5.203(e)(2)(F) a description of the capability of the materials to withstand corrosion when exposed to a combination of the CO2 stream and formation fluids; 5.203(e)(2)(J) chemical composition and temperature of the CO2 stream; and	Section 1 – Introduction Section 4.5.5 – CO2 Stream Characteristics
146.86(c)(3)(iii)	Maximum proposed injection pressure;	5.203(e)(2)(D) proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, external pressure, internal pressure, axial loading, and maximum proposed volume and/or mass of the CO2 stream to be injected;	Section 4.2.3 – Injection Tubing Design and Completion Section 4.5.1 – Injection Rate and Pressure
146.86(c)(3)(iv)	Maximum proposed annular pressure;		Section 4.5.3 – Annulus Pressure
146.86(c)(3)(v)	Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;	5.203(e)(2)(D) proposed injection rate (intermittent or continuous), maximum proposed surface injection pressure, external pressure, internal pressure, axial loading, and maximum proposed volume and/or mass of the CO2 stream to be injected;	Section 4.2.3 – Injection Tubing Design and Completion Section 4.5.1 – Injection Rate and Pressure
146.86(c)(3)(vi)	Size of tubing and casing; and	5.203(e)(2)(C) size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths	Section 4.2.2 – Production Casing Desing and Completion Section 4.2.3 – Injection Tubing Design and Completion

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.86(c)(3)(vii)	Tubing tensile, burst, and collapse strengths.	5.203(e)(2)(C) size and grade of all casing and tubing strings (e.g., wall thickness, external diameter, nominal weight, length, joint specification and construction material, tubing tensile, burst, and collapse strengths	Section 4.2.2 – Production Casing Design and Completion Section 4.2.3 – Injection Tubing Design and Completion Section 4.2.5 – Surface Casing Design and Completion
146.82(a)(7)	Proposed operating data for the proposed geologic sequestration site:	5.203(i) Operating information. (1) Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in 5.206(d) of this title, and that outlines the steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:	See Below
146.82(a)(7)(i)	Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;	5.203(i)(1)(A) the average and maximum daily injection rates, temperature, and volumes and/or mass of the CO2 stream;	Section 4.5.2 – CO2 Volume
146.82(a)(7)(ii)	Average and maximum injection pressure;	5.203(i)(1)(B) the average and maximum surface injection pressure;	Section 4.5.1 – Injection Rate and Pressure
146.82(a)(8)	Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at 146.87;	5.203(c)(2)(F) a description of the formation testing program used and the analytical results used to determine the chemical and physical characteristics of the injection zone and the confining zone; and	Section 4.4 – Pre-Operational Testing Plan
146.82(a)(9)	Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;	5.203(e)(4) Well stimulation plan. The applicant must submit a description of the proposed well stimulation program, including a description of the stimulation fluids, and a	Section 4.5.4 – Well Stimulation Procedures

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		determination that well stimulation will not compromise containment.	
146.82(a)(10)	Proposed procedure to outline steps necessary to conduct injection operation;	5.203(i) Operating information. (1) Operating plan. The applicant must submit a plan for operating the injection wells and the geologic storage facility that complies with the criteria set forth in 5.206(d) of this title, and that outlines the steps necessary to conduct injection operations. The applicant must include the following proposed operating data in the plan:	Section 4.5 – Injection Well Operating Strategy
146.82(a)(11)	Schematics or other appropriate drawings of the surface and subsurface construction details of the well;	5.203(e)(2) Construction information. The applicant must provide the following information for each well to allow the director to determine whether the proposed well construction and completion design will meet the general performance criteria in paragraph (1) of this subsection: (K) schematic drawings of the surface and subsurface construction details.	Appendix D
146.82(a)(12)	Injection well construction procedures that meet the requirements of 146.86;	5.203(e) Injection well construction. (1) Criteria for construction of anthropogenic CO2 injection wells. This paragraph establishes the criteria for the information about the construction and casing and cementing of, and special equipment for, anthropogenic CO2 injection wells that an applicant must include in an application.	Section 4.7 – Injection Well Construction and Operation Summary Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.87(a)	During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:	5.203(f) Plan for logging, sampling, and testing of injection wells before injection. The applicant must submit a plan for logging, sampling, and testing of each injection well prior to injection well operation. The plan need not include identical logging, sampling, and testing procedures for all wells provided there is a reasonable basis for different procedures. Such plan is not necessary for existing wells being converted to anthropogenic CO2 injection wells in accordance with this subchapter, to the extent such activities already have taken place. The plan must describe the logs, surveys, and tests to be conducted to verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in, the formations that are to be used for monitoring, storage, and confinement to assure conformance with the injection well construction requirements set forth in subsection (e) of this section, and to establish accurate baseline data against which future measurements may be compared. The plan must meet the following criteria and must include the following information.	Appendix D

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.87(a)(1)	Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	5.203(f)(1)(A) During the drilling of any hole that is constructed by drilling a pilot hole that is enlarged by reaming or another method, the operator must perform deviation checks at sufficiently frequent intervals to determine the location of the borehole and to assure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling.	Appendix D
146.87(a)(2)	Before and upon installation of the surface casing:	5.203(f)(1)(B) Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.	See Below
146.87(a)(2)(i)	Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	5.203(f)(1)(B) Before surface casing is installed, the operator must run appropriate logs, such as resistivity, spontaneous potential, and caliper logs.	Section 4.4.2 – Injection and Confining Zone Core Sampling
146.87(a)(2)(ii)	A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	5.203(f)(1)(C) After each casing string is set and cemented, the operator must run logs, such as a cement bond log, variable density log, and a temperature log, to ensure proper cementing.	Section 4.3 Well Drilling and Completion Design Section 4.4.2 – Injection and Confining Zone Core Sampling
146.87(a)(3)	Before and upon installation of the long string casing:	5.203(f)(1)(D) Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.	See Below

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.87(a)(3)(i)	Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and	5.203(f)(1)(D) Before long string casing is installed, the operator must run logs appropriate to the geology, such as resistivity, spontaneous potential, porosity, caliper, gamma ray, and fracture finder logs, to gather data necessary to verify the characterization of the geology and hydrology.	Section 4.4.2 – Injection and Confining Zone Core Sampling
146.87(a)(3)(ii)	A cement bond and variable density log, and a temperature log after the casing is set and cemented.	5.203(e)(1)(B)(vi) The applicant must verify the integrity and location of the cement using technology capable of radial evaluation of cement quality and identification of the location of channels to ensure that USDWs will not be endangered	Section 4.3 Well Drilling and Completion Design Section 4.4.2 – Injection and Confining Zone Core Sampling
146.87(a)(4)	A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	5.203(h) (2) Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:	Section 4.2 – Engineering Design Appendix D
146.87(a)(4)(i)	A pressure test with liquid or gas;	5.203(h)(2)(A) a pressure test with liquid or inert gas;	Section 4.4 – Pre-Operational Testing Plan
146.87(a)(4)(ii)	A tracer survey such as oxygen-activation logging;	5.203(h)(2)(B) a tracer survey such as oxygen-activation logging;	Section 5.4.2 – External Mechanical Integrity Testing
146.87(a)(4)(iii)	A temperature or noise log;	5.203(h)(2)(C) a temperature or noise log;	Section 4.4.2 – Injection and Confining Zone Core Sampling
146.87(a)(4)(iv)	A casing inspection log; and	5.203(h)(2)(D) a casing inspection log; and/or	Section 4.4.2 – Injection and Confining Zone Core Sampling

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.87(a)(5)	Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	5.203(h)(2)(E) any alternative method approved by the director, and if necessary by the Administrator of EPA under 40 CFR 146.89(e), that provides equivalent or better information approved by the director.	Not Applicable
146.87(b)	The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.	5.203(f)(3)(B) The operator must take whole cores or sidewall cores representative of the injection zone and confining zone and formation fluid samples from the injection zone. The director may require the operator to core other formations in the borehole. The director may accept data from cores and formation fluid samples from nearby wells or other data if the operator can demonstrate to the director that such data are representative of conditions at the proposed injection well. The operator must submit to the director a detailed report prepared by a log analyst that includes well log analyses (including well logs), core analyses, and formation fluid sample information.	Section 4.4.2 – Injection and Confining Zone Core Sampling
146.87(c)	The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).	5.203(f)(3)(A) The operator must record and submit the formation fluid temperature, pH, and conductivity, the reservoir pressure, and the static fluid level of the injection zone.	Section 4.4.3 – Injection Zone Characterization Appendix D
146.87(d)	At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):	5.203(f)(2)(C) The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone.	See Below

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.87(d)(1)	Fracture pressure;	5.203(f)(2)(C) The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure does not exceed the fracture pressure of the injection zone.	Section 4.4.4 – Fracture Pressure, Fluid Characteristics, and Downhole Conditions
146.87(d)(2)	Other physical and chemical characteristics of the injection and confining zone(s); and	5.203(c)(2)(B) the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;	Section 4.4.4 – Fracture Pressure, Fluid Characteristics, and Downhole Conditions
146.87(d)(3)	Physical and chemical characteristics of the formation fluids in the injection zone(s).	5.203(c)(2)(B) the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of, and the geochemistry of any formation fluids in, the storage reservoir and confining zone and any other relevant geologic formations, including geology/facies changes based on field data, which may include geologic cores, outcrop data, seismic surveys, well logs, and lithologic descriptions, and the analyses of logging, sampling, and testing results used to make such determinations;	Section 4.4.4 – Fracture Pressure, Fluid Characteristics, and Downhole Conditions

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.87(e)	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	5.203 (f)(2) Testing and determination of hydrogeologic characteristics of injection and confining zone.(A) Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.	See Below
146.87(e)(1)	A pressure fall-off test; and,	5.203(f)(2)(B)The operator must perform an initial pressure fall-off or other test and submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO2.	Section 4.4.5 – Injection and Confining Zone Formation Testing
146.87(e)(2)	A pump test; or		
146.87(e)(3)	Injectivity tests.		
146.87(f)	The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.	5.206(i) Permit conditions for Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	Section 4.5.4 – Well Stimulation Procedures Appendix D
146.88	Injection well operating requirements		See Below
146.88(a)	Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture	5.206(d)(2)(C) The operator must comply with a maximum surface injection pressure limit approved by the director and specified in the	Section 4.5.1 – Injection Rate and Pressure

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	permit. In approving a maximum surface injection pressure limit, the director must consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The director must approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non- transmissive faults or fractures transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection fluids or formation fluids in a manner that endangers USDWs. The Commission shall include in any permit it might issue a limit of 90 percent of the fracture pressure to ensure that the injection pressure does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. The director may approve a plan for controlled artificial fracturing of the injection zone.5.203(f)(2)(C) The operator must determine or calculate the fracture pressures for the injection and confining zone. The Commission will include in any permit it might issue a limit of 90% of the fracture pressure to ensure that the injection pressure	

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		does not exceed the fracture pressure of the injection zone.	
146.88(b)	Injection between the outermost casing protecting USDWs and the well bore is prohibited.	5.206(d)(2)(A) Injection between the outermost casing protecting USDWs and the well bore is prohibited.	4.2.2 Production Casing Design and Completion
146.88(c)	The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	5.206(d)(2)(D) The operator must fill the annulus between the tubing and the long string casing with a corrosion inhibiting fluid approved by the director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the director determines that such requirement might harm the integrity of the well or endanger USDWs.	Section 4.2.6 – Injection Tubing and Packer Design and Completion Section 4.3 – Well Drilling and Completion Design
146.88(d)	Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.	5.203(h)(1)(A) Other than during periods of well workover in which the sealed tubing-casing annulus is of necessity disassembled for maintenance or corrective procedures, the operator must maintain mechanical integrity of the injection well at all times.	4.2.2 – Production Casing Design and Completion and Appendix D.1, D.2, and D.3

Section 5 – Testing and Monitoring

146.87(e)	Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):	5.203(f)(2) Testing and determination of hydrogeologic characteristics of injection and confining zone.(A) Prior to operation, the operator must conduct tests to verify hydrogeologic characteristics of the injection zone.	Section 5 – Testing and Monitoring Plan
146.87(e)(1)	A pressure fall-off test; and,	5.203(f)(2)(B) The operator must perform an initial pressure fall-off or other test and	Section 5.7 – Pressure Fall-Off Testing

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		submit to the director a written report of the results of the test, including details of the methods used to perform the test and to interpret the results, all necessary graphs, and the testing log, to verify permeability, injectivity, and initial pressure using water or CO ₂ .	
146.87(e)(2)	A pump test; or		Not Applicable
146.87(e)(3)	Injectivity tests.		4.4.5 Injection and Confining Zone Formation Testing

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.90	The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	5.206(e)(1)The operator of an anthropogenic CO₂ injection well must maintain and comply with the approved monitoring, sampling, and testing plan to verify that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone. 5.206(a) (1) Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit. 5.203(j) Plan for monitoring, sampling, and testing after initiation of operation. (1) The applicant must submit a monitoring, sampling, and testing plan for verifying that the geologic storage facility is operating as permitted and that the injected fluids are confined to the injection zone. (2) The plan must include the following:	Section 5.0 – Testing and Monitoring Plan Section 5.1 – Objectives, Appendix E
146.90(a)	Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	5.203(j)(2)(A) the analysis of the CO₂ stream prior to injection with sufficient frequency to yield data representative of its chemical and physical characteristics;	Section 5.5 – Continuous Recording of Operational Parameters During Injection Section 5.11 – Testing Plan Review and Updates,

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
			Appendix E
146.90(b)	Installation and use, except during well workovers as defined in 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	5.203(j)(2)(B) the installation and use of continuous recording devices to monitor injection pressure, rate, temperature, and volume and/or mass, and the pressure on the annulus between the tubing and the long string casing, except during workovers;	Section 5.5 – Continuous Recording of Operational Parameters During Injection, 5.5.1 – Continuous Monitoring of Injection Rate and Volume, 5.5.2 – Continuous Monitoring of Injection Temperature and Pressure at Injection Well, 5.5.3 – Continuous Monitoring Injection Temperature and Pressure in Reservoir, 5.11 – Testing Plan Review and Updates
146.90(c)	Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in 146.86(b), by:	5.203(j)(2)(C) after initiation of injection, the performance on a quarterly basis of corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance set forth in subsection (e)(1)(A) of this section. The operator must report the results of such monitoring semi-annually. Corrosion monitoring may be accomplished by:	Section 5.6 – Corrosion Monitoring, 5.6.1 – Monitoring Location and Frequency, 5.11 – Testing Plan Review Updates, Appendix E

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.90(c)(1)	Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or	5.203(j)(2)(C)(i) analyzing coupons of the well construction materials in contact with the CO2 stream;	Section 5.6.1 – Monitoring Location and Frequency, Appendix E
146.90(c)(2)	Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or	5.203(j)(2)(C)(ii) routing the CO2 stream through a loop constructed with the materials used in the well and inspecting the materials in the loop; or	Section 5.6.1 – Monitoring Location and Frequency
146.90(c)(3)	Using an alternative method approved by the Director;	5.203(j)(2)(C)(iii) using an alternative method, materials, or time period approved by the director;	Not Applicable
146.90(d)	Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	5.203(j)(2)(D) monitoring of geochemical and geophysical changes, including: (i) periodic sampling of the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the injection zone and monitoring for pressure changes, and for changes in geochemistry, in a permeable and porous formation near to and above the top confining zone; (ii) periodic monitoring of the quality and geochemistry of a USDW within the AOR and the formation fluid in a permeable and porous formation near to and above the top confining zone to detect any movement of the injected CO2 through the confining zone into that monitored formation;	Section 5.2 – Overall Strategy and Approach for Testing and Monitoring Plan, 5.9 – CO2 Plume Tracking Using Groundwater Monitoring Data, 5.9.3 – USDW Monitoring Well Network, 5.11 – Testing Plan Review and Updates
146.90(d)(1)	The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and	5.203(j)(2)(D)(iii) the location and number of monitoring wells justified on the basis of the AOR, injection rate and volume, geology, and the presence of artificial penetrations and other factors specific to the geologic storage facility; and	Section 5.9.2 – Design of the Monitoring Well Network

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.90(d)(2)	The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under 146.82(a)(6) and on any modeling results in the area of review evaluation required by 146.84(c).	5.203(j)(2)(D)(iv) the monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data collected under subsection (c)(2) of this section and any modeling results in the AOR evaluation;	Section 5.9.2 – Design of the Monitoring Well Network, Appendix E
146.90(e)	A demonstration of external mechanical integrity pursuant to 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at 146.89(d) at a frequency established in the testing and monitoring plan;	5.203(h)(1)(D) At least once per year until the injection well is plugged, the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs).5.203(h)(2) Mechanical integrity testing plan. The applicant must prepare and submit a mechanical integrity testing plan as part of a permit application. The performance tests must be designed to demonstrate the internal and external mechanical integrity of each injection well. These tests may include:(D) a casing inspection log; and/or	Section 5.4.2 – External Mechanical Integrity Testing Section 5.11 – Testing Plan Review and Updates, Appendix E
146.90(f)	A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	5.203(j)(2)(G) a pressure fall-off test at least once every five years unless more frequent testing is required by the director based on site-specific information; and	Section 5.7 – Pressure Fall-Off Testing Section 5.12 – Testing Plan Review and Updates, Appendix E
146.90(g)	Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	5.203(j)(2)(E) tracking the extent of the CO2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity,	Section 5.8 – CO2 Plume and Pressure Front Tracking, Appendix E

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		or electromagnetic surveys and/or down-hole CO2 detection tools;	
146.90(g)(1)	Direct methods in the injection zone(s); and,		Section 5.2 – Overall Strategy and Approach for Testing and Monitoring Plan Section 5.11 – Testing Plan Review and Updates, Appendix E
146.90(g)(2)	Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	5.203(j)(2)(E) tracking the extent of the CO2 plume and the position of the pressure front by using indirect, geophysical techniques, which may include seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO2 detection tools;	Section 5.2 – Overall Strategy and Approach for Testing and Monitoring Plan, 5.8.2 – Plume and Pressure Front Tracking Using Indirect Geophysical Techniques, 5.11 – Testing Plan Review and Updates, Appendix E
146.90(h)	The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	5.203(j)(2)(G) additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the	Section 5.9.5 – Construction of In-Zone Monitoring Well□

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		injected fluid remain within the permitted interval.	
146.90(h)(1)	Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;		Section 5.3 – Use of Phased and/or Triggered Approach
146.90(h)(2)	The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under 3603.D;		Section 5.3 – Use of Phased and/or Triggered Approach
146.90(h)(3)	If an owner or operator demonstrates that monitoring employed under 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under 98.440 to 98.449 of this chapter. Compliance with 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;		Section 5.3 – Use of Phased and/or Triggered Approach

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.90(i)	Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under 146.84(c) and to determine compliance with standards under 144.12 of this chapter;	5.203(j)(2)(G) additional monitoring as the director may determine to be necessary to support, upgrade, and improve computational modeling of the AOR evaluation and to determine compliance with the requirements that the injection activity not allow the movement of fluid containing any contaminant into USDWs and that the injected fluid remain within the permitted interval.	Not Applicable
146.90(j)	The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under 146.88, and the most recent area of review reevaluation performed under 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at 144.39 or 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	5.207(a)(2)(E) Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter. (i) Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has: (I) reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by 5.203 or 5.206 of this title; and (II) determined whether any updates were warranted by material change in the monitoring and operational data or in the evaluation of the monitoring and operational data by the operator. (ii) Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator	Section 5.11 – Testing Plan Review and Updates, Appendix E

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.	
146.90(j)(1)	Within one year of an area of review reevaluation;	5.207(a)(2)(E) Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter.	Section 5.11 – Testing Plan Review and Updates
146.90(j)(2)	Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or	5.207(a)(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a	Section 5.9.5 – Construction of In-Zone Monitoring Well, Appendix E

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		revision is necessary to comply with the requirements of this subchapter.	
146.90(j)(3)	When required by the Director.	5.207(a)(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	Section 5.9.5 – Construction of In-Zone Monitoring Well
146.90(k)	A quality assurance and surveillance plan for all testing and monitoring requirements.	5.203(a)(4) Reports. An applicant must ensure that all descriptive reports are prepared by a qualified and knowledgeable person and include an interpretation of the results of all logs, surveys, sampling, and tests required in this subchapter. The applicant must include in the application a quality assurance and surveillance plan for all testing and monitoring, which includes, at a minimum, validation of the analytical laboratory data, calibration of field instruments, and an explanation of the sampling and data acquisition techniques.	Appendix E
146.89(a)	A Class VI well has mechanical integrity if:	5.102(36)(A) An anthropogenic CO2 injection well has mechanical integrity if:	Section 5.4 – Mechanical Integrity Test Methods
146.89(a)(1)	There is no significant leak in the casing, tubing, or packer; and	5.102(36)(A)(i) there is no significant leak in the casing, tubing, or packer; and	Section 5.4 – Mechanical Integrity Test Methods

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.89(a)(2)	There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	5.102(36)(A)(ii)there is no significant fluid movement into a stratum containing an underground source of drinking water through channels adjacent to the injection well bore as a result of operation of the injection well.	Section 5.4 – Mechanical Integrity Test Methods
146.89(b)	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in 146.88 (e);	5.203(h)(1)(C) Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, temperature, injected volumes and mass, and pressure on the annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone. If mass is determined using volume, the operator must provide calculations.	Section 5.5 – Continuous Recording of Operational Parameters During Injection
146.89(b)	To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in 146.88 (e);	5.203(h)(1)(C) Following an initial annulus pressure test, the operator must continuously monitor injection pressure, rate, temperature, injected volumes and mass, and pressure on the annulus between tubing and long string casing to confirm that the injected fluids are confined to the injection zone. If mass is determined using volume, the operator must provide calculations.	Section 5.5 – Continuous Recording of Operational Parameters During Injection
146.89(c)	At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	(D) At least once per year until the injection well is plugged, the operator must confirm the absence of significant fluid movement into a USDW through channels adjacent to the injection wellbore (external integrity) using a method approved by the director (e.g., diagnostic surveys such as oxygen-activation logging or temperature or noise logs).	Section 5.4.2 – External Mechanical Integrity Testing

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.89(c)(1)	An approved tracer survey such as an oxygen-activation log; or	5.203(h)(2)(B) a tracer survey such as oxygen-activation logging;	Section 5.4.2 – External Mechanical Integrity Testing
146.89(c)(2)	A temperature or noise log.	5.203(h)(2)(C) a temperature or noise log;	Section 5.4.2 – External Mechanical Integrity Testing
146.89(d)	If required by the Director, at a frequency specified in the testing and monitoring plan required at 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.	5.203(h)(2)(D) a casing inspection log; and/or	Section 5.6.3 – Cement Evaluation and Casing Inspection Logs
146.89(e)	The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.	5.203(h)(2)(E) any alternative method approved by the director, and if necessary by the Administrator of EPA under 40 CFR 146.89(e), that provides equivalent or better information approved by the director.	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.89(f)	In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.	5.207 Reporting and Record-Keeping(a) Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information.(1) Test records. The operator must file a complete record of all tests in duplicate with the district office within 30 days after the testing. In conducting and evaluating the tests enumerated in this subchapter or others to be allowed by the director, the operator and the director must apply methods and standards generally accepted in the industry. When the operator reports the results of mechanical integrity tests to the director, the operator must include a description of any tests and methods used. In making this evaluation, the director must review monitoring and other test data submitted since the previous evaluation.	Section 5.10 – Reporting Requirements
146.89(g)	The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.	5.206(f)(5) The director may require additional or alternative tests if the results presented by the operator do not demonstrate to the director that there is no significant leak in the casing, tubing, or packer or movement of fluid into or between formations containing USDWs resulting from the injection activity.	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.91	The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:	5.207 (a) Reporting requirements. The operator of a geologic storage facility must provide, at a minimum, the following reports to the director and retain the following information.	See Below
146.91(a)	Semi-annual reports containing:	5.207(a)(2)(C) Semi-annual report. The operator must report:	See Below
146.91(a)(1)	Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	5.207(a)(2)(C)(ii) changes to the source as well as the physical, chemical, and other relevant characteristics of the CO2 stream from the proposed operating data;	Section 5.10 – Reporting Requirements
146.91(a)(2)	Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	5.207(a)(2)(C)(iii) monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure	Section 5.10 – Reporting Requirements
146.91(a)(3)	A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	5.207(a)(2)(C)(v) a description of any event that significantly exceeds operating parameters for annulus pressure or injection pressure as specified in the permit;	Section 5.10 – Reporting Requirements
146.91(a)(4)	A description of any event which triggers a shut-off device required pursuant to 146.88(e) and the response taken;	5.207(a)(2)(C)(vi) a description of any event that triggers a shutdown device and the response taken; and	Section 5.10 – Reporting Requirements
146.91(a)(5)	The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	5.207(a)(2)(C)(iii) monthly average, maximum and minimum values for injection pressure, flow rate, temperature, and volume and/or mass, and annular pressure	Section 5.10 – Reporting Requirements
146.91(a)(6)	Monthly annulus fluid volume added; and	5.207(a)(2)(C)(iv) monthly annulus fluid volume added;	Section 5.10 – Reporting Requirements
146.91(a)(7)	The results of monitoring prescribed under 146.90.	5.207(a)(2)(C)(vii) the results of monitoring prescribed under	Section 5.10 – Reporting Requirements

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		5.206(e) of this title (relating to Permit Standards).	
146.91(b)	Report, within 30 days, the results of:	5.207(a)(2)(B) Report within 30 days. The operator must report:	See Below
146.91(b)(1)	Periodic tests of mechanical integrity;	5.207(a)(2)(B)(i) the results of periodic tests for mechanical integrity;	Section 5.4.3 – Reporting Results of MIT
146.91(b)(2)	Any well workover; and,	5.207(a)(2)(B)(iii) a description of any well workover.	Section 5.10 – Reporting Requirements
146.91(b)(3)	Any other test of the injection well conducted by the permittee if required by the Director.	5.207(a)(2)(B)(ii) the results of any other test of the injection well conducted by the operator if required by the director; and	Not Applicable
146.91(c)	Report, within 24 hours:	5.207(a)(2)(A) Report within 24 hours. The operator must report the items listed in clauses (i) through (v) of this subparagraph to the director and the appropriate district office orally as soon as practicable, but within 24 hours of discovery, and in writing within five working days of discovery. The written submission shall contain a description of the noncompliance and its cause, the period of noncompliance, including exact dates and times, and if the noncompliance has not been corrected, the anticipated time it is expected to continue, and steps taken or planned to reduce, eliminate, and prevent reoccurrence of the noncompliance. The operator shall report the following items:	Section 5.10 – Reporting Requirements
146.91(c)(1)	Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;	5.207(a)(2)(A)(ii) any evidence that the injected CO2 stream or associated pressure	Section 5.10 – Reporting Requirements

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		front may cause an endangerment to a USDW;	
146.91(c)(2)	Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	5.207(a)(2)(A)(iii) any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;	Section 5.10 – Reporting Requirements
146.91(c)(3)	Any triggering of a shut-off system (i.e., down-hole or at the surface);	5.206(d)(2)(F)(ii) If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the operator must immediately investigate and identify as expeditiously as possible the cause. If, upon investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the operator must: (III) notify the director as soon as practicable, but within 24 hours;	Section 5.10 – Reporting Requirements
146.91(c)(4)	Any failure to maintain mechanical integrity; or.	5.206(d)(2)(F)(ii) If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the operator must immediately investigate and identify as expeditiously as possible the cause. If, upon investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the operator must:(III) notify the director as soon as practicable, but within 24 hours;	Section 5.10 – Reporting Requirements
146.91(c)(5)	Pursuant to compliance with the requirement at 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of		Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	carbon dioxide to the atmosphere or biosphere.		
146.91(d)	Owners or operators must notify the Director in writing 30 days in advance of:	5.206(i) Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	See Below
146.91(d)(1)	Any planned well workover;	5.207(a)(2)(B)(iii) a description of any well workover. 5.206(i) Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first	Section 5.10 – Reporting Requirements

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	
146.91(d)(2)	Any planned stimulation activities, other than stimulation for formation testing conducted under 146.82; and	5.206(i) Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	Section 5.4 – Mechanical Integrity Test Methods

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.91(d)(3)	Any other planned test of the injection well conducted by the permittee.	5.207(a)(2)(B)(i) the results of periodic tests for mechanical integrity; (ii) the results of any other test of the injection well conducted by the operator if required by the director; and 5.206(i) Commission witnessing of testing and logging. The operator must provide the division with the opportunity to witness all planned well workovers, stimulation activities, other than stimulation for formation testing, and testing and logging. The operator must submit a proposed schedule of such activities to the Commission at least 30 days prior to conducting the first such activity and submit notice at least 48 hours in advance of any actual activity. Such activities shall not commence before the end of the 30 days unless authorized by the director.	Section 5.4 – Mechanical Integrity Test Methods

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.91(e)	Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	5.203 (a)(1)(A) Form and filing. Each applicant for a permit to construct and operate a geologic storage facility must file an application with the division in Austin on a form prescribed by the Commission. The applicant must file the application and all attachments with the division and with EPA Region 6 in an electronic format approved by EPA. On the same date, the applicant must file one copy with each appropriate district office and one copy with the Executive Director of the Texas Commission on Environmental Quality. 5.207(b)(2) The operator must submit all required reports, submittals, and notifications under this subchapter to the director and to the EPA in an electronic format approved by the director and the Regional Administrator, respectively.	Section 5.10 – Reporting Requirements
146.91(f)	Records shall be retained by the owner or operator as follows:	5.206(m) (2)The permittee shall retain records as follows:	Section 5.10 – Reporting Requirements
146.91(f)(1)	All data collected under 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.	5.206(m) (2) (A) All data collected under 5.203 of this title for Class VI permit applications shall be retained throughout the life of the geologic storage project and for 10 years following site closure.	Section 5.10 – Reporting Requirements
146.91(f)(2)	Data on the nature and composition of all injected fluids collected pursuant to 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the	5.206(m) (2) (B) Data on the nature and composition of all injected fluids collected pursuant to 5.203(i)(1)(D) of this title shall be retained until 10 years following site closure. The director may require the operator to	Section 5.10 – Reporting Requirements

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	Director at the conclusion of the retention period.	submit the records to the director at the conclusion of the retention period.	
146.91(f)(3)	Monitoring data collected pursuant to 146.90(b) through (i) shall be retained for 10 years after it is collected.	5.206(m) (2) (C) Monitoring data collected pursuant to 5.203(j)(2) of this title shall be retained for 10 years after it is collected.	Section 5.10 – Reporting Requirements
146.91(f)(4)	Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at 146.93(f) and (h) shall be retained for 10 years following site closure.	5.206(m) (2) (D) Well plugging reports, post-injection site care data, including data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements of subsection (k)(6) of this section and paragraph (4) of this subsection shall be retained for 10 years following site closure.	Section 5.10 – Reporting Requirements
146.91(f)(5)	The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.	5.206(m) (2) (E)The director has authority to require the operator to retain any records required in this subchapter for longer than 10 years following site closure.	Section 5.10 – Reporting Requirements
146.88(e)(1)	Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	5.206(d)(2)(E) The operator must install and use continuous recording devices to monitor the injection pressure, and the rate, volume, and temperature of the CO2 stream. The operator must monitor the pressure on the annulus between the tubing and the long string casing. The operator must continuously record, continuously monitor, or control by a preset high-low pressure sensor switch the wellhead pressure of each injection well.	Section 5.5 – Continuous Recording of Operational Parameters During Injection, 5.8 – CO2 Plume and Pressure Front Tracking 5.10 – Reporting Requirements Table 5-10

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
Section 6 – Plugging Plan			
146.92(a)	Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	5.203(k) Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that includes the following: (2) proposals for activities to be undertaken prior to plugging an injection well, specifically: (A) flushing each injection well with a buffer fluid; (B) performing tests or measures to determine bottomhole reservoir pressure; (C) performing final tests to assess mechanical integrity; and	Section 6.2.1 – Flushing Well with Kill Weight Fluid, 6.2.4 – Planned External MITs, 6.3.2 – Final P&A
146.92(b)	Well plugging plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	5.206 (a)(1)Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.5.206(j) Permit conditions for well plugging. The operator of a geologic storage facility must maintain and comply with the approved well plugging plan required by5.203(k) of this title.5.203(k)Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that includes the following:	Section 6.1 – Objectives Section 6.3 – Injection Well Zonal Isolation and Final P&A
146.92(b)(1)	Appropriate tests or measures for determining bottomhole reservoir pressure;	5.203(k)(2)(B)performing tests or measures to determine bottomhole reservoir pressure;	Section 6.1 – Objectives Section 6.2.3 – Planned

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
			Tests or Measures to Determine Bottomhole Pressure□
146.92(b)(2)	Appropriate testing methods to ensure external mechanical integrity as specified in 146.89;	5.203(k)(2)(C) performing final tests to assess mechanical integrity; and	Section 6.1 – Objectives□ Section 6.3.2 – Final P&A; Section 6.4 – Notification and Record Keeping
146.92(b)(3)	The type and number of plugs to be used;	5.203(k)(1)(A)the type and number of plugs to be used;	Section 6.1 – Objectives□ Section 6.2.5 – CO2 Compatible Materials; Section 6.4 – Notification and Record Keeping; Tables 6-4, 6-5, and 6-6
146.92(b)(4)	The placement of each plug, including the elevation of the top and bottom of each plug;	5.203(k)(1)(B)the placement of each plug, including the elevation of the top and bottom of each plug;	Tables 6-4, 6-5, and 6-6
146.92(b)(5)	The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and	5.203(k)(1)(C) the type, grade, and quantity of material to be used in plugging and information to demonstrate that the material is compatible with the CO2 stream; and	Section 6.2.5 – CO2- Compatible Materials, Tables 6-4, 6-5, and 6-6□
146.92(b)(6)	The method of placement of the plugs.	5.203(k)(1)(D)the method of placement of the plugs;	Section 6.2.5 – CO2 – Compatible Materials, Tables 6-4, 6-5, and 6-6

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.92(c)	Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at 144.39 or 144.41 of this chapter, as appropriate.	5.203(k)(3) a proposal for giving notice of intent to plug monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that: (A) the operator notifies the director at least 60 days before plugging a well. At this time, if any changes have been made to the original well plugging plan, the operator must also provide a revised well plugging plan. At the discretion of the director, an operator may be allowed to proceed with well plugging on a shorter notice period; and (B) the operator will file a notice of intention to plug and abandon (Form W-3A) a well with the appropriate Commission district office and the division in Austin at least five days prior to the beginning of plugging operations;	Section 6.3.2 – Final P&A; Section 6.6 – Amendments to the P&A Plan□

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.92(d)	Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	5.203(k)(4) a plugging report for monitoring wells that penetrate the base of usable quality water and all injection wells. The applicant's plan must ensure that within 30 days after plugging the operator will file a complete well plugging record (Form W-3) in duplicate with the appropriate district office. The operator and the person who performed the plugging operation (if other than the operator) must certify the report as accurate;5.206(m)(6)The operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the post-injection storage facility care period. The operator must submit the records to the director at the conclusion of the retention period, and the records must thereafter be retained at the Austin headquarters of the Commission.	Section 6.3.2 – Final P&A
146.82(a)(16)	Proposed injection well plugging plan required by 146.92(b);	5.203(k) Well plugging plan. The applicant must submit a well plugging plan for all injection wells and monitoring wells that includes the following:	Section 6.1 – Objectives Section 6.3 – Injection Well Zonal Isolation and Final P&A

Section 7 – Post Injection Site Care and Closure Plan

Section 7 – Post Injection Site Care and Closure Plan			
146.82(a)(17)	Proposed post-injection site care and site closure plan required by 146.93(a);	5.203 (m) Post-injection storage facility care and closure plan. The applicant must submit a post-injection storage facility care and closure plan. The plan must include:	Section 7 – Post-Injection Site Care and Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.82(a)(18)	At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by 146.93(c);	(8) information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria: (A) all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards; (B) estimation techniques must be appropriate and EPA-certified test protocols must be used where available; (C) predictive models must be appropriate and tailored to the site conditions, composition of the CO2 stream, and injection and site conditions over the life of the geologic storage project; (D) predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available; (E) reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements; (F) an analysis must be performed to identify and assess aspects of the alternative post-injection storage facility care timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration; (G) an approved quality assurance and quality	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		control plan must address all aspects of the demonstration; and (H) any additional criteria required by the director.	
146.93(a)	The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	5.203(k) (1) (A) Post-injection storage facility care and closure plan. (A)The operator of an injection well must maintain and comply with the approved post-injection storage facility care and closure plan. 5.206 (a) (1) Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	Section 7 – Post-Injection Site Care and Site Closure Plan
146.93(a)(1)	The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	5.203(m) Post-injection storage facility care and closure plan.	Section 7 – Post-Injection Site Care and Site Closure Plan
146.93(a)(2)	The post-injection site care and site closure plan must include the following information:	5.203(m) Post-injection storage facility care and closure plan. The applicant must submit a post-injection storage facility care and closure plan. The plan must include:	See Below
146.93(a)(2)(i)	The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);	5.203(m)(2)the pressure differential between pre-injection and predicted post-injection pressures in the injection zone;	Section 7.1 – Objectives; Section 7.2 – Calculation of Pre- and Post-Injection Pressure Differentials; Table 7-1: Maximum Pressure

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
			Differential by Year for Injection Wells No. 01, No. 02, and No. 03
146.93(c)	Demonstration of alternative post-injection site care timeframe. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.		Not Applicable
146.93(c)(1)	A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:	5.203(m) Post-injection storage facility care and closure plan. The applicant must submit a post-injection storage facility care and closure plan. The plan must include: (7) consideration and documentation of:	Not Applicable
146.93(c)(1)(i)	The results of computational modeling performed pursuant to delineation of the area of review under 146.84;	5.203(m)(7)(A) the results of computational modeling performed pursuant to delineation of the AOR under subsection (d) of this section;	Not Applicable
146.93(c)(1)(ii)	The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be	5.203(m)(7)(B) the predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;	fluids may not be forced into any USDWs, and/or the timeframe for pressure decline to pre- injection pressures;	
146.93(c)(1)(ix)	A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;	5.203(m)(7)(I) a description of the well construction and an assessment of the quality of plugs of all abandoned wells within the AOR;	Not Applicable
146.93(c)(1)(viii)	The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;	5.203(m)(7)(H) the presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic storage project or any other projects in proximity to the predicted/modeled, final extent of the CO2 plume and area of elevated pressure;	Not Applicable
146.93(c)(2)	Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:	5.203(m)(8) information submitted to support the demonstration in paragraph (1) of this subsection, which shall meet the following criteria:	Not Applicable
146.93(c)(2)(i)	All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	5.203(m)(8)(A) all analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;	Not Applicable
146.93(c)(2)(ii)	Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	5.203(m)(8)(B)estimation techniques must be appropriate and EPA-certified test protocols must be used where available;	Not Applicable
146.93(c)(2)(iii)	Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;	5.203(m)(8)(C)predictive models must be appropriate and tailored to the site conditions, composition of the CO2 stream, and injection and site conditions over the life of the geologic storage project;	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.93(c)(2)(iv)	Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	5.203(m)(8)(D) predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;	Not Applicable
146.93(c)(2)(v)	Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	5.203(m)(8)(E) reasonably conservative values and modeling assumptions must be used and disclosed to the director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;	Not Applicable
146.93(c)(2)(vi)	An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.	5.203(m)(8)(F) an analysis must be performed to identify and assess aspects of the alternative post-injection storage facility care timeframe demonstration that contribute significantly to uncertainty. The operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration;	Not Applicable
146.93(c)(2)(vii)	An approved quality assurance and quality control plan must address all aspects of the demonstration; and,	5.203(m)(8)(G) an approved quality assurance and quality control plan must address all aspects of the demonstration; and	Not Applicable
146.93(c)(2)(viii)	Any additional criteria required by the Director.	5.203(m)(8)(H) any additional criteria required by the director.	Not Applicable
146.93(a)(2)(ii)	The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under 146.84(c)(1);	5.203(m)(3) the predicted position of the CO2 plume and associated pressure front at closure as demonstrated in the AOR evaluation required under subsection (d) of this section;	Section 7.3 – Predicted Position of the CO2 Plume and Pressure Front at Site Closure

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.93(a)(2)(iii)	A description of post-injection monitoring location, methods, and proposed frequency;	5.203(m)(4) a description of the proposed post-injection monitoring location, methods, and frequency;	Section 7.4 – Post-Injection Monitoring Plan; Section 7.4.2 – Monitoring Above the UCCZ and USDW; Section 7.4.3 – In-Zone CO2 Plume and Pressure Front Tracking;
146.93(a)(2)(iv)	A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to 146.91(e); and,	5.203(m)(5) a proposed schedule for submitting post- injection storage facility care monitoring results to the director;	7.4.4 – Submitting PISC Monitoring Results
146.93(a)(2)(v)	The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.		Section 7.1 – Objectives; Section 7.4.3 – In-Zone CO2 Plume and Pressure Front Tracking
146.93(a)(3)	Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at 144.39 or 144.41 of this chapter, as appropriate.	5.206(k)(1)(C) Upon cessation of injection, the operator of a geologic storage facility must either submit an amended plan or demonstrate to the director through monitoring data and modeling results that no amendment to the plan is needed.5.206(k)(1)(B) The operator must update the plan in accordance with 5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the operator may modify and resubmit the post- injection site care and site closure plan for the director's approval within 30 days of such change. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject	Section 7.4.1 – PISC and Site Closure Plan Reviews and Amendments

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		to the permit modification requirements in 5.202 of this title, as appropriate.	
146.93(a)(4)	At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.	5.206(k)(1)(B) The operator must update the plan in accordance with 5.207(a)(2)(D)(vi) of this title. At any time during the life of the geologic sequestration project, the operator may modify and resubmit the post- injection site care and site closure plan for the director's approval within 30 days of such change. Any amendments to the post-injection site care and site closure plan must be approved by the director, be incorporated into the permit, and are subject to the permit modification requirements in 5.202 of this title, as appropriate.	Section 7.4.1 – PISC and Site Closure Plan Reviews and Amendments

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.93(b)	The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	5.206(k)(2) Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	Section 7.1 – Objectives
146.93(b)(1)	Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.	5.206(k)(2) Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	Section 7.1 – Objectives

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.93(b)(2)	If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	5.206(k)(2) Post-injection storage facility monitoring. Following cessation of injection, the operator must continue to conduct monitoring as specified in the approved plan until the director determines that the position of the CO2 plume and pressure front are such that the geologic storage facility will not endanger USDWs.	Section 7.1 – Objectives

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.93(b)(3)	Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	5.206(k)(3) Prior to closure. Prior to authorization for storage facility closure, the operator must demonstrate to the director, based on monitoring, other site-specific data, and modeling that is reasonably consistent with site performance that no additional monitoring is needed to assure that the geologic storage facility will not endanger USDWs. The operator must demonstrate, based on the current understanding of the site, including monitoring data and/or modeling, all of the following: (A) the estimated magnitude and extent of the facility footprint (the CO₂ plume and the area of elevated pressure); (B) that there is no leakage of either CO₂ or displaced formation fluids that will endanger USDWs; (C) that the injected or displaced fluids are not expected to migrate in the future in a manner that encounters a potential leakage pathway into USDWs; (D) that the injection wells at the site completed into or through the injection zone or confining zone will be plugged and abandoned in accordance with these requirements; and (E) any remaining facility monitoring wells will be properly plugged or are being managed by a person and in a manner approved by the director.	Section 7.5 – Demonstration of Non-Endangerment of USDW; Figure 7-3 Extent of Maximum CO₂ Plume and Pressure Front Stabilized 55 Years from Start of Injection; Section 7.4.2 – Monitoring Above the UCCZ and USDW; Section 7.6.3 – Site Restoration;

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.93(b)(4)	If the demonstration in paragraph (b)(3) of this section cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.		Not Applicable
146.93(d)	Notice of intent for site closure. The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	5.206(k)(4) Notice of intent for storage facility closure. The operator must notify the director in writing at least 120 days before storage facility closure. At the time of such notice, if the operator has made any changes to the original plan, the operator also must provide the revised plan. The director may approve a shorter notice period.	Section 7.6 Site Closure Plan
146.93(e)	After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	5.206(k)(5) Authorization for storage facility closure. No operator may initiate storage facility closure until the director has approved closure of the storage facility in writing. After the director has authorized storage facility closure, the operator must plug all wells in accordance with the approved plan required by 5.203(k) of this title and submit a plugging record (Form W-3) as required by 3.14 of this title (relating to Plugging).	Section 7.6 Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.93(f)	The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	5.206(k)(6) Storage facility closure report. Once the director has authorized storage facility closure, the operator must submit a storage facility closure report within 90 days that must thereafter be retained by the Commission in Austin. The report must include the following information:	Section 7.1 – Objectives; Section 7.6 – Site Closure Plan
146.93(f)(1)	Documentation of appropriate injection and monitoring well plugging as specified in 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;	5.206(k)(6)(A) documentation of appropriate injection and monitoring well plugging. The operator must provide a copy of a survey plat that has been submitted to the Regional Administrator of Region 6 of the EPA. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks including the Latitude/Longitude or X/Y coordinates of the surface location in the NAD 27, NAD 83, or WGS 84 coordinate system, a labeled scale bar, and northerly direction arrow;	Section 7.6.4 – Documentation of Site Closure
146.93(f)(2)	Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and	5.206(k)(6)(B) documentation of appropriate notification and information to such state and local authorities as have authority over drilling activities to enable such state and local authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zones; and	Section 7.6.4 – Documentation of Site Closure
146.93(f)(3)	Records reflecting the nature, composition, and volume of the carbon dioxide stream.	5.206(k)(6)(C) records reflecting the nature, composition, volume and mass of the CO2 stream. If mass is determined using volume, the operator must provide calculations.	Section 7.6.4 – Documentation of Site Closure

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.93(g)	Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	5.206(l) Permit conditions for deed notation. The operator of a geologic storage facility must record a notation on the deed to the facility property; on any other document that is normally examined during title search; or on any other document that is acceptable to the county clerk for filing in the official public records of the county that will in perpetuity provide any potential purchaser of the property the following information:	Section 7.6.4 – Documentation of Site Closure
146.93(g)(1)	The fact that land has been used to sequester carbon dioxide;	5.206(l)(2) that land has been used to geologically store CO ₂ ;	Section 7.6.4 – Documentation of Site Closure
146.93(g)(2)	The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and	5.206(l)(3) that the survey plat has been filed with the Commission; 5.206(l)(4) the address of the office of the United States Environmental Protection Agency, Region 6, to which the operator sent a copy of the survey plat; and	Section 7.6.4 – Documentation of Site Closure
146.93(g)(3)	The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.	5.206(l)(5) the volume and mass of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred. If mass is determined using volume, the operator must provide calculations.	Section 7.6.4 – Documentation of Site Closure
146.93(h)	The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must	5.206(m)(6) The operator must retain for 10 years following storage facility closure records collected to prepare the permit application, data on the nature and composition of all injected fluids, and records collected during the post-injection storage facility care period. The operator must submit	Section 7.6.4 – Documentation of Site Closure

Section 8 – Emergency Response			
146.82(a)(19)	Proposed emergency and remedial response plan required by 146.94(a);	5.203(l) Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that:	Section 8 – Emergency and Remedial Response Plan
146.84(f)	The emergency and remedial response plan (as required by 146.94) and the demonstration of financial responsibility (as described by 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	5.203(l) (1) Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that: (1) accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;	Section 8 – Emergency and Remedial Response Plan Figure 8-2
146.88(e)(2)	Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and	5.206(d)(2)(F) (i) The operator must comply with the following requirements for alarms and automatic shut-off systems. (i) The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.	8.6 Response Plans for Risk Scenarios

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.88(e)(3)	Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.	5.206(d)(2)(F) (i) The operator must comply with the following requirements for alarms and automatic shut-off systems.(i) The operator must install and use alarms and automatic shut-off systems designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate or other parameters diverge from permitted ranges and/or gradients. On offshore wells, the automatic shut-off systems must be installed down-hole.	Not Applicable
146.88(f)	If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:	5.206(d)(2)(F) (ii) If an automatic shutdown is triggered or a loss of mechanical integrity is discovered, the operator must immediately investigate and identify as expeditiously as possible the cause. If, upon investigation, the well appears to be lacking mechanical integrity, or if monitoring otherwise indicates that the well may be lacking mechanical integrity, the operator must:	Section 8.6 – Response Plans for Risk Scenarios
146.88(f)(1)	Immediately cease injection;	(I) immediately cease injection;	Section 8.6 – Response Plans for Risk Scenarios
146.88(f)(2)	Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;	(II) take all steps reasonably necessary to determine whether there may have been a release of the injected CO2 stream into any unauthorized zone;	Section 8.6.3 – Injection Well Monitoring Equipment Failure
146.88(f)(3)	Notify the Director within 24 hours;	5.206(d)(2)(F)(ii)(III) notify the director as soon as practicable, but within 24 hours;	Section 8.6 – Response Plans for Risk Scenarios

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.88(f)(4)	Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and	5.206(d)(2)(F)(ii)(IV) restore and demonstrate mechanical integrity to the satisfaction of the director prior to resuming injection; and	Section 8.6 – Response Plans for Risk Scenarios
146.88(f)(5)	Notify the Director when injection can be expected to resume.	5.206(d)(2)(F)(ii)(V) notify the director when injection can be expected to resume.	Section 8.6 – Response Plans for Risk Scenarios
146.94	Emergency and remedial response		
146.94(a)	As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	5.203(l)Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that: (2) describes actions to be taken to address escape from the permitted injection interval or movement of the injection fluids or formation fluids that may cause an endangerment to USDWs during construction, operation, closure, and post-closure periods; 5.206(a)(1) Each condition applicable to a permit shall be incorporated into the permit either expressly or by reference. If incorporated by reference, a specific citation to the rules in this chapter shall be given in the permit. The requirements listed in this section are directly enforceable regardless of whether the requirement is a condition of the permit.	Section 8.6 – Response Plans for Risk Scenarios
146.94(b)	If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:	5.206(g)(3)(A) If an operator obtains evidence that the injected CO2 stream and associated pressure front may cause an endangerment to USDWs, the operator must:	Section 8.6 – Response Plans for Risk Scenarios

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.94(b)(1)	Immediately cease injection;	5.206(g)(4)(A)(i) immediately cease injection;	Section 8.6 – Response Plans for Risk Scenarios
146.94(b)(2)	Take all steps reasonably necessary to identify and characterize any release;	5.206(h)(3)(A)(ii) take all steps reasonably necessary to identify and characterize any release;	Section 8.6 – Response Plans for Risk Scenarios
146.94(b)(3)	Notify the Director within 24 hours; and	5.206(h)(3)(A)(iii) notify the director as soon as practicable but within at least 24 hours; and	Section 8.6 – Response Plans for Risk Scenarios
146.94(b)(4)	Implement the emergency and remedial response plan approved by the Director.	5.206(h)(3)(A)(iv) implement the approved emergency and remedial response plan.	Section 8.6 – Response Plans for Risk Scenarios
146.94(c)	The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.	5.206(h)(4)Resumption of injection. The director may allow the operator to resume injection prior to remediation if the operator demonstrates that the injection operation will not endanger USDWs.	Section 8.6 – Response Plans for Risk Scenarios
146.94(d)	The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at 144.39 or 144.41 of this chapter, as	5.207(a)(2)(E) Annual updates. The operator must maintain and update required plans in accordance with the provisions of this subchapter. (i) Operators must submit an annual statement, signed by an appropriate company official, confirming that the operator has: (I) reviewed the monitoring and operational data that are relevant to a decision on whether to reevaluate the AOR and the monitoring and operational data that are relevant to a decision on whether to update an approved plan required by 5.203 or 5.206 of this title; and (II) determined whether any updates were warranted by material change in the	Section 8.10 – Plan Review

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:	monitoring and operational data or in the evaluation of the monitoring and operational data by the operator. (ii) Operators must submit either the updated plan or a summary of the modifications for each plan for which an update the operator determined to be warranted pursuant to subclause (I) of this clause. The director may require submission of copies of any updated plans and/or additional information regarding whether or not updates of any particular plans are warranted.	
146.94(d)(1)	Within one year of an area of review reevaluation;		
146.94(d)(2)	Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or	5.207(a)(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	Section 8.10 – Plan Review
146.94(d)(3)	When required by the Director.	5.207(a)(3) The director may require the revision of any required plan following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the director or whenever the director determines that such a revision is necessary to comply with the requirements of this subchapter.	Section 8.10 – Plan Review

Section 9 – Financial Assurance			
146.82(a)(14)	A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under 146.85;	5.203(n) Fees, financial responsibility, and financial assurance. The applicant must pay the fees, demonstrate that it has met the financial responsibility requirements, and provide the Commission with financial assurance as required under 5.205 of this title (relating to Fees, Financial Responsibility, and Financial Assurance).	Section 9.2 – Financial Assurance Demonstration
146.85(a)(6)(ii)	When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.		Section 9.2 – Financial Assurance Demonstration
146.84(f)	The emergency and remedial response plan (as required by 146.94) and the demonstration of financial responsibility (as described by 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.	5.203(l) (1) Emergency and remedial response plan. The applicant must submit an emergency and remedial response plan that: (1) accounts for the entire AOR, regardless of whether or not corrective action in the AOR is phased;	Section 9.7 – Emergency and Remedial Response

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85	Financial responsibility		Section 9.2 – Financial Assurance Demonstration
146.85(a)	The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:	5.205(b)(1)A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9.3 – Estimated Coverage Amounts
146.85(a)(1)	The financial responsibility instrument(s) used must be from the following list of qualifying instruments:	5.205 (c)(2)(A)The applicant must include in an application for a geologic storage facility permit:	Section 9.0 – Introduction

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(a)(1)(ii)	Surety Bonds.	5.205(c)(2)(A)(ii) a copy of the form of the bond or letter of credit that will be filed with the Commission;5.205(c)(2)(B) A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.5.205(c)(2)(D)(i) The issuer of any geologic storage facility bond filed in satisfaction of the requirements of this subsection must be a corporate surety authorized to do business in Texas. The form of bond filed under this subsection must provide that the bond be renewed and continued in effect until the conditions of the bond have been met or its release is authorized by the director.	Claimed as PBI

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(a)(1)(iii)	Letter of Credit.	5.205(c)(2)(A)(ii) a copy of the form of the bond or letter of credit that will be filed with the Commission; 5.205(c)(2)(B) A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director. 5.205(c)(2)(D)(ii) Any letter of credit filed in satisfaction of the requirements of this subsection must be issued by and drawn on a bank authorized under state or federal law to operate in Texas. The letter of credit must be an irrevocable, standby letter of credit subject to the requirements of Texas Business and Commerce Code, 5.101 – 5.118. The letter of credit must provide that it will be renewed and continued in effect until the conditions of the letter of credit have been met or its release is authorized by the director.	Claimed as PBI
146.85(a)(1)(i)	Trust Funds.		Claimed as PBI
146.85(a)(1)(vii)	Any other instrument(s) satisfactory to the Director.		Section 9.2 – Financial Assurance Demonstration

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(a)(2)	The qualifying instrument(s) must be sufficient to cover the cost of:	5.205(c)(2)(C)The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements:5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9.4 – Corrective Action
146.85(a)(2)(i)	Corrective action (that meets the requirements of 146.84);	5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9.4 – Corrective Action

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(a)(2)(ii)	Injection well plugging (that meets the requirements of 146.92);	5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9.4 – Corrective Action Section – 9.5 Well Plugging Section – 9.6 Post-Injection Site Care and Site Closure Plan Section 9.7 – Emergency and Remedial Response
146.85(a)(2)(iii)	Post injection site care and site closure (that meets the requirements of 146.93); and	5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9.6 – Post-Injection Site Care and Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(a)(2)(iv)	Emergency and remedial response (that meets the requirements of 146.94).	5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9.7 – Emergency and Remedial Response
146.85(a)(3)	The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	5.205(c)(2)(C) The determination of the amount of financial assurance for a geologic storage facility is subject to the following requirements: (i) The director must approve the dollar amount of the financial assurance. The amount of financial assurance required to be filed under this subsection must be equal to or greater than the maximum amount necessary to perform corrective action, emergency response, and remedial action, post-injection monitoring and site care, and closure of the geologic storage facility, including plugging of wells, at any time during the permit term in accordance with all applicable state laws, Commission rules and orders, and the permit. The cost estimate must be performed for each phase separately and must be based on the costs to the	Section 9.5 – Well Plugging

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		Commission of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator;	
146.85(a)(4)	The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.		Section 9.3 – Estimated Coverage Amounts
146.85(a)(4)(i)	Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	5.205(c)(2)(D)(iii) The qualifying financial responsibility instruments must comprise protective conditions of coverage. Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions; specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument; and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.	Section 9.3 – Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(a)(4)(i)(A)	Cancellation – for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.	5.205(c)(2)(D)(iii)(I) Cancellation. An owner or operator must provide that its financial instrument may not cancel, terminate, or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the director. The cancellation must not be final until at least 120 days after the Commission receives the cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable or possible, any funds from the instrument being cancelled must be released within 60 days of notification by the director.	Section 9.3 – Estimated Coverage Amounts
146.85(a)(4)(i)(B)	Renewal – for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	5.205(c)(2)(D)(iii)(II) Renewal. If a financial instrument expires, the owner or operator must renew the financial instrument for the entire term of the geologic storage project. The instrument may be automatically renewed as long as the operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.	Section 9.3 – Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(a)(4)(i)(C)	Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.	5.205(c)(2)(D)(iii)(III) Financial instrument to remain in effect. Cancellation, termination, or failure to renew shall not occur and the financial instrument shall remain in full force and effect if on or before the date of expiration: (-a-) the director deems the facility abandoned; (-b-) the permit is terminated or revoked or a new permit is denied; (-c-) closure is ordered by the director or a United States district court or other court of competent jurisdiction; (-d-) the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or (-e-) the amount due is paid.	Section 9.3 – Estimated Coverage Amounts
146.85(a)(5)	The qualifying financial responsibility instrument(s) must be approved by the Director.	5.205(c)(2)(B) A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.	Section 9.3 – Estimated Coverage Amounts
146.85(a)(5)(i)	The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (146.82).	5.205(c)(2)(B) A geologic storage facility shall not receive CO2 until a bond or letter of credit in an amount approved by the director under this subsection and meeting the requirements of this subsection as to form and issuer has been filed with and approved by the director.	Section 9.3 – Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(a)(5)(ii)	The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.	5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines	Section 9.4 – Corrective Action

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
146.85(a)(5)(iii)	The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.		Section 9.3 – Estimated Coverage Amounts
146.85(a)(6)	The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.		Section 9.2 – Financial Assurance Demonstration
146.85(a)(6)(i)	In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.		Not Applicable
146.85(b)(1)	The owner or operator must maintain financial responsibility and resources until:		Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(b)(1)(i)	The Director receives and approves the completed post-injection site care and site closure plan; and	5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9.6 – Post-Injection Site Care and Site Closure Plan
146.85(b)(1)(ii)	The Director approves site closure.	5.205(b)(1) A person to whom a permit is issued under this subchapter must provide annually to the director evidence of financial responsibility that is satisfactory to the director. The owner or operator must demonstrate and maintain financial responsibility for corrective action, injection well plugging, post-injection storage facility care and storage facility closure, and emergency and remedial response until the director has provided written verification that the director has determined that the facility has reached the end of the post-injection storage facility care period.	Section 9.6.2 – Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(c)	The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.	5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines	Section 9.6.2 – Site Closure Plan

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
146.85(c)(1)	The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.	5.205(c)(2)(C)(ii) qualified professional engineer licensed by the State of Texas, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act, must prepare or supervise the preparation of a written estimate of the highest likely amount necessary to close the geologic storage facility. The owner or operator must submit to the director the written estimate under seal of a qualified licensed professional engineer, as required under Occupations Code, Chapter 1001, relating to Texas Engineering Practice Act; and	Section 9.6.2 – Site Closure Plan
146.85(c)(2)	During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of	5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any	Section 9.3 – Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	review and corrective action plan (146.84), the injection well plugging plan (146.92), the post-injection site care and site closure plan (146.93), and the emergency and remedial response plan (146.94).	decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
146.85(c)(3)	The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (146.84), the injection well plugging plan (146.92), the post-injection site care and site closure plan (146.93), and the emergency and response plan (146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.	5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines	Section 9.3 – Estimated Coverage Amounts

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
146.85(c)(4)	Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.	5.205(c)(2)(G) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the director or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the operator has received written approval from the director.	Section 9.3 – Estimated Coverage Amounts
146.85(d)	The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.	5.205(d)(1)The owner or operator must notify the Commission of adverse financial conditions that may affect the owner's or operator's ability to carry out injection well plugging and post-injection storage facility care and closure. An owner or operator must file any notice of bankruptcy in accordance with 3.1(f) of this title (relating to Organization Report; Retention of Records;	Not Applicable

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
		Notice Requirements). The owner or operator must give such notice by certified mail.	
146.85(d)(1)	In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.	5.205(d)(2) The owner or operator filing a bond must ensure that the bond provides a mechanism for the bond or surety company to give prompt notice to the Commission and the owner or operator of any action filed alleging insolvency or bankruptcy of the surety company or the bank or alleging any violation that would result in suspension or revocation of the surety or bank's charter or license to do business.	Not Applicable
146.85(d)(2)	A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.		Appendix J-2
146.85(e)	The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by 146.84), injection well plugging (as required by 146.92), post-injection site care and site closure (as	5.205(c)(2)(F)The owner or operator of a geologic storage facility must provide to the director, and the director must approve, annual written updates of the cost estimate to increase or decrease the cost estimate to account for any changes to the AOR and corrective action plan, the emergency response and remedial action plan, the injection well plugging plan, and the post-injection storage facility care and closure plan. The Director must approve any	Section 9.3 – Estimated Coverage Amount

EPA 40 CFR	EPA 40 CFR Description	Texas State Citation and Requirement	Corresponding Section
	required by 146.93), and emergency and remedial response (as required by 146.94).	decrease or increase to the initial cost estimate. During the active life of the geologic storage project, the owner or operator must revise the cost estimate no later than 60 days after the director has approved the request to modify the AOR and corrective action plan, the injection well plugging plan, the post-injection storage facility care and closure plan, and the emergency and response plan, if a change in any of these plans increases the cost. If a change to a plan decreases the cost, any withdrawal of funds must be approved by the director. Any decrease to the value of a financial assurance instrument must first be approved by the director. The revised cost estimate must be adjusted for inflation as specified at paragraph (2)(E) of this subsection. The owner or operator must provide to the director, within 60 days of notification by the director, an adjustment of the cost estimate if the director determines during the annual evaluation of the qualifying financial responsibility instruments that the most recent demonstration is no longer adequate to cover the cost of corrective action, injection well plugging and post-injection storage facility care and closure, and emergency and remedial response.	
146.85(f)	The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.		Not Applicable



der u d e r e d e a er a r R e
r e e e a d

5

9

9

☐☐☐☐ ☒☒☐ ☐☐☐ - ☒☒☒ R D ☐☐☐☐ ☒☒

9

9

5

Re-arbitration rate

er u y e a

_____M_____b_____arb_____u_____re_____ra_____e_____

5

9

5

9

9

9

February 5

5

5

o e d e e e a e r a r R e e e e e e e a d e

□ a □ e □ □ □ □ □ □ □ □

□ a □ e □ □ □ □ □ □ □ □

Mar 1998 M b 1998 arb 1998 u 1998 re 1998 ra e 1998 M b 1998
 ub 1998 ed a 1998 der r u d 1998 e 1998 r 1998 a 1998 er 1998 a 1998 a 1998
 e 1998 r 1998 e a 1998 r e 1998 e y 1998 r 1998 e R 1998 e arb 1998 a 1998 ure a d 1998 ra e 1998
 1998 r 1998 e 1998 r 1998 e 1998 e r 1998 u y 1998 e a 1998 e r 1998 e 1998 a 1998 e 1998 u 1998
 1998 bay 1998 e 1998 e u 1998 a 1998 Ba 1998 e 1998 e d 1998 u 1998 e e d 1998 r 1998 a 1998 r 1998 e 1998 a d 1998
 1998 a 1998 e 1998 arb 1998 d 1998 d e 1998 e 1998 d e r 1998 e d 1998 r 1998 e a 1998 e y 1998 ure 1998 du 1998 r a 1998
 1998 ur e 1998

[illegible]

[REDACTED] e d e
 a re e a re re ed e e u der a d ab u e u ab y e r e
 e r r e u e r a a d u der r u d u r e d r a e r D be
 r e e d r r u u e e y e e r e

The data is a summary of the Federal Reserve's data on the number of people who are employed in the United States. The data is presented in a table with the following columns: Year, Total Employment, and Unemployment. The data is for the years 1990 through 2000. The total employment is shown in millions of people, and the unemployment rate is shown as a percentage.

The R deareura aerare R a be
 de ed mer e er year e re o rae a a y a d a red u ed r
 e a e da er e D e e e a r r u e r a y a u d r e u D
 e da er e a addre ed a r by r ba by re e e r a r a e y
 e e e de e a d e e a d r r r a

The following table provides a detailed breakdown of the data collected from the survey, categorized by the type of service used and the frequency of use. The data is presented in a structured format, allowing for easy comparison and analysis of the results. The table is organized into columns representing the service type, the frequency of use, and the corresponding percentage of respondents. The data is presented in a clear and concise manner, facilitating a thorough understanding of the survey findings.

a	e	5							

[illegible]

Claimed as PBI

Claimed as PBI

	a	e							

☐ e ☐ y	e e e u ber
Claimed as PBI	
e a D er e y Ma a e e	5
e a De ar e ub a e y	5
a e e a Re r e	
e a ar ad d de De ar e	5
Re	r 5
a —Bra d Ma e	5 5 5
e a De ar e a ura Re ur e	5
Claimed as PBI	
a a Re e e er	
a e e a Re r e	
a a Re e e er ur	

SDS **ss** **r** **d** **r**

GSDT Module: **r** **e** **r** **a** **r**

Tab(s): **e** **e** **r** **a** **ab** **Fa** **y** **r** **a** **a** **d** **r** **e** **r** **r** **a** **ab**

e **e** **e** **e** **b** **e** **r** **y** **e** **r** **a** **a** **ub** **e** **D**

☒ **Required reading day dea** **[40 CFR 146.82(a)(1)]**

a	e								

9

dada a med e de der bed e a re e
r r y ad mer eab my e e da re re e ed a rea e b ara e er re u
a rea e era ra e e a

[illegible]

bebe

[illegible][illegible]

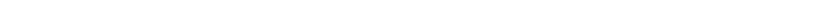
Claimed as PBI

[illegible]

□□□□□□ □u□ □ary□□□□□□ e□u□ab□□y□

Ce r e area u l a b e r e e a d a e e r e d e e

Claimed as PBI



a	e								

[illegible][illegible]

Claimed as PBI

a e ara be ee e r a er bear e ab e e a d

er. D e D are a a ed

e r e e ed e e e d e ad ara er ed e r a
e u a Ba dee ed dea r e ue ra ur e

- Claimed as PBI**

- [illegible]

- ☐ Claimed as PBI
er a er a a e
ad e r ey Claimed as PBI a era ee ad
Claimed as PBI ae tree ed ee e
a

a	e								



Claimed as PBI

Curriculum

Claimed as

CLAIMED

Chattanooga

DDI

BDI

PR

e e au d e b a ra e e a r

☐ r ☐ r ☐ a ☐ ☐ ☐ ☐ ☐ u ☐ d ☐ a ☐ d ☐ y ☐ e ☐ ☐ ☐ ☐ ☐ e ☐ a ☐ u ☐ ☐ ☐ ☐ a ☐ d ☐ e ☐ ☐ ☐ ☐ e ☐ d ☐ a ☐ ☐ ☐ ☐ a ☐ ☐ ☐ ☐ a ☐ ☐ ☐ ☐ a ☐ ☐ ☐ ☐ e ☐ ☐ ☐ ☐ ☐ e ☐

Future B5 a a e e de de ed a e be ee e Fe

a d a d a u a u d r e d u e e r e e

Claimed as PBI

Stained as T-BI

ee aad v a ara er e rea ere u d be a be e

and under a e e e d e e e e a d e

ere a ad e e ere e e a rea e ar re e ed

ere read ed by a ere e e rea e ar u e

era v u d a e e e d r e r a r a e e e v d e d e r a v

and breathe every day, assured that the air we breathe is clean and pure.

[illegible]

ed a e e e ed ara e era v e a d e e

ud e era e a era re a rd u a are a

[illegible]

 R **d** **r**

runder eende aua eer eender aae

u e a d b r e r e u r e r b u d a r e e r e a a d e r e

□ □ e d □ e □ □ □ □ □ r u □ □ □ □ □ d e a e d a d □ □ □ □ r e e □ □ □ e □ □ d e □ □ □ e □ □ r □ □ □ e a □ □ r a □ □ □ □ □ □

de mea e R a de r bed e ba a d ra a e r e e e u ara e er

re de a e a ed a d e ra e e r re e a r e ar a e e ra

□ □ □ □ □ □ R □ e r □ □ e d □ □ e □ □ d e □ □ a □ r e □ e d □ □ □ □ □ r □ r a e □ □ e □ □ □ □ □ e □ □ □ □ □ □ □ □ a □ □ □

de r e r e e d a a u r r a a a e e r e a b y

a d r y e e e a e r a r a y e a e d r r e a a d a

da a re e a ed a a e e e r e y e re ure bu du

ed e a er Re re e e

☐ ☐ ☐ a d ☐ ☐ ☐

☐ a ☐ e



dur e e e e a d r a d r e u r e d e e a e r e e e e
e a r r r r b r e u d r a r u b e e e e e e a d r u d a e r
a b e e e e r b a b e a a r a y r e e d

[illegible]

ed e e e a r R e r e e e e
a d

[illegible]



Claimed as PBI

[illegible]

Claimed as PBI

ar e e ra ere de ed e R e e ra ed e
 M b de e ed a rre e a rrea ar a e e ra a a
 de ed a e e e a a a a er a du be au e e er e e a
 e ed a a e b re e r e e u e d u a da ba d e

	a	e		5						

XXXXXXXXXXXX **Res** XXXXX **SD** **S** XXX **ss** XXX

GSDT Module: F XXXX Re XXXXX b my De XXXX ra XXXX

Tab(s): XXXXXX a e ab a d a a XXXX ab e XXXX a XXXX ru e XXX ab XXX

le e u e XXXX e b XXXX XXXX er y XXXX XXXX r a XXXX a XXXX ub XXXX ed XXXX e XXXX D XXX

☒ De XXXX ra XXXXXXXX a a re XXXXX b my **[40 CFR 146.82(a)(14) and 146.85]** XXX

XXXX XXXXXXXXXXXX XXXX **s r** XXXXXXX

le XXXXXXX- XXX e XXXX ru XXXXXXX a a d XXXX era XXXXXXX d XXXXXXX r d e a a u d a e XXXX e XXXX
le XXXXXXX ru XXXX de XXXX a XXXX de XXXX de a XXXX a d e XXXX a XXXX r XXXX e XXXX e XXXX
r XXXX e XXXX e XXXX e XXXX ru XXXXXXX a d e XXXX ed XXXX re XXXXXXX r XXXX a d r XXXX de a XXXX
le XXXX XXXX a XXXXXXX a b e XXXX e XXXX XXXX re a XXXX FR XXXXXXX b XXXX e XXXX XXXXXXX a XXX
a a e b e XXXX e XXXX a XXXX a d XXXX e d e XXXX are a XXXX e XXXX e XXXX de XXXX e XXXX
ad u XXXX b a e d XXXX e XXXX ra XXXX ra XXXX d a a XXXX e d a XXXX e XXXX ra XXXX e XXXX a d XXXX e XXXX
materials were aligned with EPA's XXXX u XXXX a XXXXXXX XXXXXXX d a e d u e XXXX 5 XXXXXXX e XXXX *Class*
VI Well Construction – Concerns with Casing Metallurgy – DO NOT REPLY e a XXXX Ma XXXX
B XXXX y XXXX e XXXXXXX r u d a e r XXXX e XXXXXXX XXXX r XXXX e a XXXX r XXXX e XXXX e XXXX y XXXX
XXXXX a XXXX XXXX a XXXX a d e XXXX a XXXX a XXXX u e XXXX 5 XXXXXXX Me a u r y XXXX u XXXX a XXXXXXX
XXXXX e XXXX XXXX e Me a u r y XXXX u XXXX a XXXXXXX u d a d d r e a y XXXX XXXX e r XXXX r e a d XXXX e XXXX
le e r y XXXX e XXXX e a u r y XXXX r XXXX e r d u XXXX a XXXX a d XXXX e XXXX u b XXXX

XXXX M b XXXX a XXXXXXX e XXXX a XXXX u XXXX u e XXXX [REDACTED] XXX

Claimed as PBI [REDACTED] XXXX e XXXX u b XXXX
de XXXXXXX u d XXXX e XXXX e XXXX trade XXXX r XXXX e XXXX e XXXX e a e XXXX r a e XXXX e XXXX a d XXXX e XXXX
re XXXX e XXXX de e r XXXX ed by XXXX de a e d re e r XXXX r XXXX de XXXX

le XXXX r d u XXXXXXX a XXXXXXX u e a XXXX b XXXX [REDACTED] XXX

[REDACTED] XXX

[REDACTED] XXX

Claimed as PBI [REDACTED] XXX

[REDACTED] XXX

[REDACTED] XXX

[REDACTED] XXXX r XXXX e XXXX a e XXXX a XXXX e XXXXXXX e r e XXXX e XXXX XXXX a XXXX e XXXX u b u a r XXXX D a a XXXX b e XXX

le XXXX ed dur XXXX e XXXX ru XXXXXXX r XXXX e XXXX a XXXX e XXXX e XXXX re XXXX era XXXX a XXXX d XXXX a d a XXXX e XXXX

le XXXXXXX ru XXXX a d XXXX era XXXXXXX r a e y XXXX e XXXX e XXXX re u XXXX a XXXX e d e d XXXX

[REDACTED] XXX

[REDACTED] XXX

Claimed as PBI [REDACTED] XXX

[REDACTED] XXX

[REDACTED] XXX

[REDACTED] XXX

le e d e XXXXXXX e a XXXX e r XXXX XXXX a XXXXXXX r R e XXXX XXXX r e XXXX e XXXXXXX e XXXX XXXXXXX XXX
XXXX a d XXXX XXXX

le a e XXXXXXX XXXX

a	e								



Claimed as PBI

9

5- The standard Model of the Adequate Yearly Progress
 real time results would be a current year be read the
 current year the results of the Adequate Yearly Progress
 5- a based on the results of the Adequate Yearly Progress
 and be used to determine the Adequate Yearly Progress Rule

□□□□ □□s□□□□□□dM□□□□r□□□

e e r e u r e FR M b d e e d a r e e
e a d M r a r e r e u a r b a d a r a e
a e b e e a a d e d e e e

red

Claimed as PBI

Claimed as PBI

Claimed as PBI [REDACTED] e a e r e
ere e e d a r d a a e e e r e d u e a d r e u r e
ra

e e a d M a a u e e a e a a d e e
 a d r e u r e d e d e y a a a d a e r
 d e y e a e a a y a d u e e e a d e
 e u d a e e R b u d a e a d e e e a d
 e e e a a r e d e e e r a a a e d u e a d
 r e u r e r a

☐ e ☐☐☐☐☐ y ☐☐☐ e ☐ a ☐ e ☐ ar ☐☐☐ ere ☐☐☐☐ dered a ☐ r ☐ r ☐ a ☐ e ☐ r ☐ d ☐ e ☐ y ☐☐☐☐ e ☐☐☐ e ☐☐
e ☐ e ☐☐☐ a ☐ d ☐ ☐☐☐ r ☐☐☐ r ☐ a ☐ e ☐ y

•

[REDACTED]

Claimed as

© 2011 Pearson Education, Inc. All rights reserved. This publication is protected by copyright. No part of this publication may be reproduced, stored in a retrieval system, or transmitted, in any form or by any means, electronic, mechanical, photocopying, recording, or by any information storage or retrieval system, without permission in writing from Pearson Education, Inc.

THE

☐ e ☐ a ☐ u ☐ a ☐ a d r ☐ e ☐ e ☐ a ☐ d e ☐ e ☐ e ☐ a ☐ b e

Claimed as PBI

[illegible]

a	e								

[illegible]

e e r e e e e e e e r e e a a e e a e u e r u e e e e e r u e e e
y e e e e r e

The data generated from the experimental data are used to determine the effect of the different parameters on the performance of the system. The results are presented in the following table.

The and month are recorded and are recorded as every
the year

- [illegible]

Injection Well Plugging GSDT Submissions

GSDT Module:

Tab(s): e e u ab

eaueebeye r a aub ede D

☒ e e u a [40 CFR 146.82(a)(16) and 146.92(b)]

□□□□ □□s□□□□□□□□□□S□□□□□□r□□□□dS□□□□□□s□□r□□

The first three are the most common and are the most important. The first is the most common and is the most important. The second is the most common and is the most important. The third is the most common and is the most important.

ExxonMobil's strategy for PISC monitoring is based on the same systems and processes as described in the 2015-2016 Annual Report. The company's PISC monitoring system is a risk-based system that includes a number of key elements. The system is designed to identify and assess potential risks to the company's financial performance and to take appropriate action to mitigate those risks. The system is based on a number of key principles, including the following:

The Moberly area is a small town in the heart of Missouri. It is a beautiful area with a rich history. The town was founded in 1820 and has since then grown into a thriving community. The area is known for its scenic views and its friendly people. The Moberly area is a great place to live and visit.

QUESTION

	a	e							

9

Claimed as FBI

M b

u e d a a r e d u u e r e u d a e a d a a e a d

e u r e a r a r e r a D r e e e e e

u d a e a d a e a e e a r e d u e e a r a u d r e

e e e e D e u r a e

□ **S** □ □ □ **d** **S** □ □ □ □ □ □ □ **s** **r** □ □ □ **SD** □ **S** □ □ □ **ss** □ □ □ **s** □

GSDT Module:

Tab(s):

			a	d			e				ure	a	b

9

eaueebeyeraaubaedD

☒ Add enclosure a [40 CFR 146.82(a)(17) and 146.93(a)]

GSDT Module: ☐ er ☐ a ☐ e ☐ ☐ ☐ ☐ ☐ ☐ ☐ e ☐ r ☐ a ☐ e ☐ De ☐ ☐ ☐ r ☐ a ☐ ☐ ☐ ☐

Tab(s): ab y a a er a e e ra e re ue ed

eaueebeyeraarabubedD

☐ ☐ ☐ ☐ er ☐ a ☐ ☐ e ☐ ☐ ☐ ☐ ☐ ☐ ☐ ☐ e r a ☐ e d e ☐ ☐ ☐ ☐ r a ☐ ☐ ☐ [40 CFR 146.82(a)(18) and 146.93(c)]

 r dR d Rs s

[illegible][illegible]

e d e e a er a r R e r e e e

9

[illegible]

documented about the release and M... a... era... y... e... a... based...
release... e... ar... ere... de... ed... r... r... a... e... e... ur... e... e... a... ure... e... e... r... e... ar...
... uded...

Claimed as PBI

Claimed as FBI Free
y e a e ar e a a e e e y e e e a e a
e a e d d e r r e d r e e a

[illegible]

e d e e a e r a r R e r e e e
 a d

a	e								

[illegible]



Claimed as PBI

Redacted information is a common occurrence in the RFP process. Redacted information is a common occurrence in the RFP process.

Redacted information



Claimed as PBI

Redacted information is a trademark of the company. Redacted information is a trademark of the company.

Redacted information



Claimed as PBI

Redacted information is a trademark of the Redacted Information and is a

Redacted Information



Claimed as PBI



Claimed as PBI



Claimed as PBI

9

□□□□ □□□r□□dd□□□□□□□r□□□□□□□r□□□□□□□□

e e a er r a bee re ue ed tur ua FR
 a add Ca ter a e er a re ue ed by e r ra Dre
 Mb re e e re ue a dre da r ra ey a e r e a
 ra M du e e D

[illegible]

- The data described in the Rater's report is not a true reflection of the data collected by the FBI. The data is not a true reflection of the data collected by the FBI. The data is not a true reflection of the data collected by the FBI.
- The data is not a true reflection of the data collected by the FBI. The data is not a true reflection of the data collected by the FBI. The data is not a true reflection of the data collected by the FBI.
- The data is not a true reflection of the data collected by the FBI. The data is not a true reflection of the data collected by the FBI. The data is not a true reflection of the data collected by the FBI.
- The data is not a true reflection of the data collected by the FBI. The data is not a true reflection of the data collected by the FBI. The data is not a true reflection of the data collected by the FBI.

5

o **e** **d** **e** **e** **a** **r** **R** **e** **r** **e** **e** **e** **a** **d**

[illegible]

□

□

□

□

□□a□e□□□□e□□□□a□y□□e□□Ba□□□□

□□e□d□e□□□□□□□□e□□a□□□□□□er□□□□□□□□a□□□□□□□□r□□e□□□□□□r□□e□□□□□□e□□□□□□□□e□□□□□□□□□□□□□□□□□□□
□□□□a□d□□□□□□□□

□a□e□□□□□□□□□□



Underground Injection Control – Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 2 – SITE CHARACTERIZATION

Rose Carbon Capture and Storage Project

Jefferson County, Texas

ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2025

SECTION 2 – SITE CHARACTERIZATION

TABLE OF CONTENTS

2.0	Site Characterization	11
2.1	Objectives	11
2.2	Regional Geology	12
2.3	Major Stratigraphic Units: Confining and Injection Zones	13
2.3.1	Lower Confining Zone	14
2.3.2	Upper Frio Formation	15
2.3.3	Anahuac Formation	15
2.3.4	Fleming Formation	15
2.3.5	Upper Composite Confining Zone	16
2.3.6	Regional Shale Beds.....	16
2.4	Regional Structural Setting	16
2.5	Site Geology	17
2.5.1	Overview	17
2.5.2	Summary of Detailed Analyses for Site-Specific Geological Characterization	17
2.5.3	Site-Specific Data Acquisition.....	18
2.5.4	Site Location and Identification of Injection Intervals and Confining Zones.....	18
2.5.5	Top and Bottom Elevations of Injection and Confining Zones.....	20
2.5.6	Geologic Characteristics of the Injection Zone.....	21
2.5.7	Geologic Characteristics of the Confining Zones	25
2.5.8	Local Geologic Structure	27
2.5.9	Seismic Data	28
2.6	Geomechanics and Petrophysics	32
2.6.1	Local Stress Conditions.....	32
2.6.2	Elastic Moduli	33
2.6.3	Injection Zone Fracture Gradient Calculation	34
2.6.4	Capillary Pressure Data	34
2.7	Evaluation of Surface Air and Soil Gas Monitoring Data	35
2.8	Reservoir Characterization and 3D Geologic Modeling	35
2.8.1	Geologic Model of the AoR.....	35
2.8.2	Structural Model	35

CONFIDENTIAL BUSINESS INFORMATION

2.8.3	Net and Non-Net Model.....	36
2.8.4	Net Facies Model	37
2.8.5	Net-to-Gross Model	38
2.8.6	Porosity Model	39
2.8.7	Permeability Model.....	40
2.8.8	Injection Zone Permeability Test Results.....	40
2.8.9	Injection Zone Storage Potential	40
2.8.10	Model Uncertainties.....	41
2.9	Assessment of Injection Interval and Confining Zone Geochemical Reactions.....	41
2.9.1	Summary of Available Geochemical Data	41
2.9.2	Modeling Approach for Potential Geochemical Reactions	42
2.9.3	Updates to Preliminary Geochemical Models in Permit Application	42
2.9.4	Site-Specific Geochemical Model Methodology.....	43
2.9.5	Simulating Initial Brine-Mineral Equilibration and CO ₂ Reactions	44
2.9.6	Summary of Site-Specific Geochemical Model Results	44
2.9.7	Summary of Mass Transfer Potential Resulting from CO ₂ Injection	47
2.9.8	Potential Uncertainty in Geochemical Reaction Path Model	47
2.9.9	Summary of Predicted Geochemical Reactions and Potential for USDW Endangerment.....	48
2.10	Hydrogeology.....	48
2.10.1	Identification of USDW	48
2.10.2	Total Dissolved Solids and Groundwater Flow Direction	49
2.10.3	Evaluation of the Lowermost USDW	50
2.11	Seismic Risk and Fault-Slip Potential for AoR.....	55
2.12	Site Suitability	56
2.12.1	Local Geology and Injection Interval Suitability.....	57
2.12.2	Summary of Storage Capacity.....	57
2.12.3	Summary of Confining Zone(s) Suitability.....	58
2.12.4	Summary of CO ₂ Stream Compatibility and Suitability	58

List of Tables

Claimed as PBI	60
	60

Claimed as PBI

Claimed as PBI

List of Figures (Compiled in Appendix B – Site Characterization Files)

Claimed as
PBI

Claimed as
PBI

Claimed as PBI

Claimed as PBI



-Page Intentionally Left Blank-

2.0 Site Characterization

On March 7, 2024, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) submitted a Class VI Permit Application (Application) to the U.S. Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage Project (Project). Section 2 of the Application contained site characterization information in compliance with the requirements of Code of Federal Regulations, Title 40, Section 146.82(a)(3) [40 CFR 146.82(a)(3)] and Texas Administrative Code, Part 1 Title 16 Chapter 5. Since that time, additional site characterization data have become available through the stratigraphic well [REDACTED] data acquisition and analysis program being conducted by ExxonMobil.

The purpose of this amendment is to incorporate the recently obtained data into the Application to facilitate the evaluation of site suitability for sequestration of carbon dioxide (CO₂). Revisions to Section 2 are summarized in a separate table to identify where key data updates and evaluations were made. Analysis of the stratigraphic well data further refined the site characterization and pre-operational plans originally submitted in Application. In many areas, the stratigraphic well data also confirmed ExxonMobil's understanding of the site and increased confidence in the reservoir characterization and subsequent modeling.

ExxonMobil is undertaking the Project in Jefferson County, Texas to sequester a [REDACTED] [REDACTED] The purpose of the site characterization section is to identify the potential risks and demonstrate to the satisfaction of the Underground Injection Control (UIC) Program Director that the Project site is suitable for the sequestration project. The key aspects of this demonstration are that the geologic formations provide adequate storage capacity to store the intended volume of injected CO₂ and a competent confining zone is present that will contain the injected CO₂ throughout the life of the Project.

ExxonMobil has completed a thorough review of site characterization data and analyses from multiple data types including public, proprietary, and licensed data sets. A high degree of confidence has been gained during this process regarding the effectiveness of the storage and confining properties of the sequestration site. As described in this amendment, the recently obtained data from the stratigraphic well aligns with the initial site characterization. This alignment strengthens the lines of evidence supporting the finding that the Class VI siting criteria requirements are satisfied and underground sources of groundwater (USDW) are protected.

2.1 Objectives

The following objectives were developed to demonstrate compliance with the requirements of 40 CFR 146.82:

- Provide maps and cross sections of the area of review (AoR) [40 CFR 146.82(a)(3)(i) and 146.82(a)(2)];
- Identify the location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the AoR, along with an assessment that they will not interfere with containment [40 CFR 146.82(a)(3)(ii)];

CONFIDENTIAL BUSINESS INFORMATION

- Summarize available data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) and on lithology and facies changes [40 CFR 146.82(a)(3)(iii)];
- Discuss the available geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)];
- Summarize the available information on the seismic history of the area, including the presence and depths of seismic sources, and an assessment of the potential for seismicity to interfere with containment [40 CFR 146.82(a)(3)(v)];
- Provide geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area [40 CFR 146.82(a)(3)(vi)];
- Present maps and stratigraphic cross sections indicating the general vertical and lateral limits of the USDWs and water wells completion details within the AoR, their positions relative to the injection zone, and the direction of water movement (where known) [40 CFR 146.82(a)(5)]; and
- Summarize the available baseline geochemical data on subsurface formations, including the USDWs in the AoR [40 CFR 146.82(a)(6)].

2.2 Regional Geology

The Project is in Jefferson County, Texas within the Houston Embayment of the Gulf of Mexico Basin, as presented on Figure B-1 (Roberts-Ashby et al., 2014). On shore and near-shore, the Gulf of Mexico Basin is often referred to as the Gulf Coast region. The stratigraphic column of the Houston Embayment is presented on Figure B-2 (Baker Jr., 1995). The Gulf of Mexico Basin was formed by crustal extension and seafloor spreading during the breakup of Pangea that took place in the Mesozoic Era. A regional unconformity at the base of the sedimentary section is marked by the base of an evaporite layer (Galloway, 2008). These substantial evaporitic deposits (up to 4 km thick) became a defining characteristic for later structural evolution of the Basin. Salt deposition ceased at the end of the Late Jurassic Era, as continued rifting produced oceanic crust.

The outline and morphology of the present-day Gulf of Mexico Basin was sculpted by subsidence and rimming carbonate platform formation by the Early Cretaceous Era (Galloway, 2008). The Cenozoic Era depositional episodes along the northwestern Gulf of Mexico Basin are fluvial-deltaic and shore-zone dominated, which reflect major phases of adjacent North American structural events (Galloway, 2008).

There were five major North American tectonic phases that influenced deposition in the Gulf of Mexico Basin: (1) Laramide uplift, (2) the mid-Cenozoic thermal phase, (3) Basin and Range tectonism, (4) southern Appalachian and Cumberland Plateau uplift and erosion, and (5) Rocky Mountain plateau tectonic uplift. Specifically, the southern Appalachian and Cumberland Plateau uplift during the Cenozoic Miocene Epoch shifted the center of deposition from the northwest basin margin to the east, including present-day eastern Texas (Galloway, 2008).

Thick sedimentary sequence deposition within the Gulf of Mexico Basin was initiated in the Cenozoic Era that included a series of “off-stepping” sediment wedges (Galloway, 2008). These sedimentary wedge sequences thicken basin-ward and were largely deformed by early Cenozoic-age growth faults that extend through Eocene and Oligocene-aged formations. The

combination of subsidence and rapid sediment loading upon a thick salt substrate resulted in significant gravity tectonics. Some of these gravity tectonic structures include growth faults, allochthonous salt bodies, salt welds, listric normal faults, salt diapirs with their related synclines and minibasins, and basin-floor compressional fold-belts (Galloway, 2008). Hyper-subsidence caused periodic structural down-warp and oceanic transgression, resulting in shale deposition atop sand sequences. The Oligocene Epoch off-stepping deposition initiated underlying salt movement upward and basin-ward, creating major salt canopies (Galloway, 2008). Salt withdrawal facilitated by sedimentation resulted in the movement of salt basin-ward creating withdrawal synclines and Gulf Shelf Minibasins, such as that underlying the Project area as presented in Figure B-3 (Galloway, 2008). The resulting salt canopies are located offshore.

As shown in Figure B-3, the Project site is contained within one of the northernmost and few land-based Shelf Minibasins, north of the Oligocene – Miocene Detachment. Figure B-4 is a regional cross section of the northern Gulf Coast region, constructed approximately 100 miles east of the Project and is labeled on Figure B-3 as Fig. 6 (Galloway, 2008). The upper cross section in Figure B-4 presents the geologic age and structural features of sedimentary units in the area, while the lower cross section presents the interpreted depositional environments along the same cross section. Onshore Miocene and Oligocene-age sediments exhibit relatively gentle dip in the vicinity of the Project, although formation dip steepens basin-ward and in areas with faulting within the Lower Miocene, Oligocene, and underlying strata, as well as in areas exhibiting underlying salt features. The associated depositional environment for the Oligocene and younger sediments are associated with fluvial deltas, shore zones, and sandy shelves (Galloway, 2008).

To summarize, the stratigraphy of the northern Gulf of Mexico Basin exhibits characteristics associated with divergent continental margins. A major unconformity is evident at the base of the sedimentary column, marked by initial onlapping of strata along the subsiding basin margin. Subsequent to subsidence, basin margin aggradation occurred through off-lapping deposition, creating shelf edge and slope systems that exhibit faulting related to depositional loading and underlying salt movement (Galloway 2008). This continued off-lapping deposition created the coastal plain and continental shelf, which have maintained a high degree of continuity throughout geologic time, up to the present day (Galloway, 2008). The depositional sequences throughout the Cenozoic Era are bounded by maximum flooding surfaces, marine and subaerial erosional unconformities, sediment starvation episodes, and faunal gaps (Galloway, 2008).

2.3 Major Stratigraphic Units: Confining and Injection Zones

Claimed as PBI
All formations underlying the UCCZ and overlying the lower confining zone (LCZ) are included in the injection zone, with the exception of the Anahuac Shale.

The injection intervals of the Fleming Formation underlie the UCCZ. **Claimed as PBI**

Claimed as PBI The Anahuac Shale occurs below the **Claimed as PBI** and serves as a laterally continuous, interim sealing unit and a significant vertical flow barrier above the **Claimed as PBI**

2.3.1 Lower Confining Zone

Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01,
No. 02, and No. 03

While not included in the LCZ, the Vicksburg Formation is a ubiquitous Upper Texas Gulf Coast interval underlying the shales of the Frio Formation and is comprised primarily of shales resulting from muddy prodeltaic shelf deposition (Loucks et al., 1978). Sand deposition increases up-section, though sand occurrence within the Vicksburg in the Upper Texas Gulf Coast was more isolated compared to the sands found in the Lower Texas Gulf Coast. The Vicksburg can also be considered a regional confining unit along the Gulf Coast (Chowdhury and Turco, 2006).

2.3.2 Upper Frio Formation

The Frio Formation consists of alternating shales and sands, stemming from progradational shore-zone systems of the Gulf coastal plain. Specifically, in the Houston area and during the Early Oligocene, deposition of large volumes of sand from the fluvially dominated Houston and Central Mississippi deltas occurred, with subsequent wave reworking resulting in thick, sand-rich prograding shore-zone systems fronted by muddy shelf sequences (Galloway et al., 2000). Also, periodic salt withdrawal during the Mid-Oligocene triggered a brief phase of tilting, collapse, and submarine erosion that interrupted margin progradation.

Long-term retreat of the Houston and Central Mississippi Delta systems occurred during the late Oligocene Era, although high sediment load allowed for aggradation of coastal plain, delta and shore-zone systems at this time associated with the Upper Frio. Galloway et al. (2000) indicates that between deltaic systems, the Frio contains wave-dominated shore-zone systems “nourished by longshore reworking of sediment from the deltaic headlands. [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED] The analysis of core data from the stratigraphic well showed porosity values to be generally consistent with regional data, with some of the best quality sands within the [REDACTED] having permeabilities in [REDACTED]

Claimed as PBI

[REDACTED] Appendix B.2 presents the available core analyses results.

2.3.3 Anahuac Formation

The Anahuac Formation is located within the injection zone, overlying the Frio Formation, and underlying the Fleming Formation. It is a thick, continuous shale interval. The Anahuac Formation (Anahuac Shale) was deposited during a transgressive event following Frio deposition (Galloway, 2008). Prograding Miocene intervals, including the Fleming Formation, cap the Anahuac transgression (Swanson et al., 2013).

2.3.4 Fleming Formation

Early Miocene sediments of the Fleming Formation at the Project site are comprised of thick successions of fluvial to fluvially dominated deltaic sands that include more proximal facies than that of the underlying Oligocene-aged Frio intervals. The Red River became the dominant fluvial source, resulting in deposition of the fluvially dominated Calcasieu Delta System (Galloway et al., 2000). During the Miocene, hyper-subsidence and collapse were observed and resulted in subsidence events and periodic deposition of mudstones and transgressive shales that are interbedded throughout the Lower Miocene. Note that the Lower Miocene is referred to as the Fleming Formation and Oakville Sandstone throughout the Texas Gulf Coast, depending on the location (Chowdhury and Turco, 2006). In the Upper Gulf Coast region, the Fleming is the primary name of the Lower Miocene section.

The Lower Miocene was characterized by high sediment supply rates and general deltaic progradation in the Project area. Some transgressive sequences interrupted the Lower Miocene deposition, but the Lower Miocene is mainly bracketed by the underlying Anahuac Shale and overlying UCCZ that include the Amph 'B' Shale as the major transgressive sequence.

South of the Project site, the estimated porosities of the Miocene reservoirs range from 5 to 38%, with an average of 28% (Carr et al., 2017). A review of available literature also indicated that permeabilities range from 16 to 1,600 mD with an average of 338 mD (Carr et al., 2017). Analysis of the Lower Miocene sands at the Project site show consistent reservoir characteristics, with core porosities from samples taken in the stratigraphic well that exceed [REDACTED] Core data from the stratigraphic well are included in Appendices B.1 and B.2 of this document.

2.3.5 Upper Composite Confining Zone

The UCCZ is a thick, muddy sequence that includes the Middle Miocene Amph 'B' Shale, a regionally continuous, transgressive marine unit (Galloway, 2008), that is recognized by the U.S. Geological Survey (USGS) National Assessment of Carbon Dioxide Storage Resources to be a good sealing unit and, therefore, a competent confining zone as required for CO₂ sequestration project sites (Roberts-Ashby et al., 2014). Additionally, Carr et al. (2017) further define the Amph 'B' as:

"A mudrock unit informally called the Amph B and encompassing the Amphistegina B biostratigraphic zone is the thickest and most extensive regional confining zone in the Miocene section of the upper Texas coast. The Amph B records a major transgressive event in the northwest Gulf of Mexico Basin that marks the end of the early Miocene" (Carr et al., 2017).

2.3.6 Regional Shale Beds

The Anahuac and the UCCZ, including the Amph 'B' Shale, are among those that are considered regional shale marker beds. The Amph 'B' Shale can be regionally correlated in logs and is thick enough to be identifiable in seismic datasets. Gulf Coast hydrocarbon production trends also indicate that the Amph 'B' Shale provides a regional fluid-migration barrier (Lu et al., 2017). The Anahuac Shale is a "world class seal" consisting of a regional shale bed in the Houston Embayment that provides a competent confining zone for hydrocarbons (Swanson et al., 2013). Based on the ability of the Anahuac Formation to trap hydrocarbons, the Anahuac Formation is considered as a confining zone restricting the vertical movement of CO₂ and will effectively isolate the Upper Frio Formation from the Fleming Formation.

2.4 Regional Structural Setting

The Project site is located in the Houston Embayment as shown on Figure B-1. Sedimentary units in the region generally dip toward the center of the Gulf of Mexico, roughly perpendicular to the coastline, as shown on Figure B-7, which presents the structural elevation of the Frio Formation top (Swanson et al., 2013). The Miocene units generally follow this structural trend, also dipping toward the center of the Gulf of Mexico. Figure B-8 presents a regional dip-oriented cross section showing the formations deepening to the southeast (Baker, 1995). As shown in Figure B-8, the top of the Anahuac and underlying formations deepen quickly to the southeast of the Project site, reflecting the depositional system and the numerous faults in the region.

Faulting in the area includes syndepositional normal faults, with the downthrown blocks typically occurring toward the Gulf of Mexico. These are largely classified as growth faults that are

common in the Gulf Coast region and were formed by simultaneous subsidence during sediment loading (Loucks et al., 1978). For example, the Vicksburg and Frio Formations are transected by these types of faults related to rapid sediment loading and subsidence, occurring within broad fault zones (i.e., the Frio Fault Zone and the Vicksburg Fault Zone, Figure B-9). The Vicksburg Fault Zone occurs southeast of the Project site, as shown on Figure B-9 (Loucks et al., 1978). Similarly, major faults occur within deeper portions of the Frio Formation in the Frio Fault Zone. (Loucks et al., 1978). Major faults in the region occur most frequently in Oligocene units, although some faults may extend to the Miocene and up to ground surface. Many oil and gas fields in the Houston Embayment contain Oligocene production, indicating that the faulting in the region often facilitates both structural and stratigraphic trapping (Swanson et al., 2013).

As discussed in more detail below, faults in the Project area are less common than reported for the region and are characterized as post-depositional normal faults with the majority having minor amounts of offset in the injection and upper confining zone.

2.5 Site Geology

2.5.1 Overview

Regional geologic observations informed the initial local geologic characterization process. In the Application, ExxonMobil took advantage of new site-specific and sub-regional characterization data to fulfill the requirements listed in 40 CFR 146.82. The data sources used for site characterization within and surrounding the AoR include various regional and local publications, seismic data (two-dimensional [2D] and three-dimensional [3D]), existing well logs, along with limited pressure and core data.

For this amendment, an extensive list of test results were analyzed and used to refine the site-specific geologic characterization:

Claimed as
PBI

Appendices B.1 to B.3 provide these data.

2.5.2 Summary of Detailed Analyses for Site-Specific Geological Characterization

The following list presents the topics for detailed analysis in the site-specific geological characterization:

CONFIDENTIAL BUSINESS INFORMATION

- The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zones in the AoR and a determination that they would not interfere with containment [40 CFR 146.82(a)(3)(ii)];
- Review of the available data on the depth, areal extent, and thickness of the injection and confining zones, and facies changes based on analysis of literature data and the stratigraphic well geophysical well log and core analyses;
- Assess data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s) including geology/facies changes [40 CFR 146.82(a)(3)(iii)];
- Evaluation of the available geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s) [40 CFR 146.82(a)(3)(iv)];
- Provide maps and stratigraphic cross sections indicating the USDWs, water wells and springs within the AoR, their positions relative to the injection zone, and the direction of water movement, where known [40 CFR 146.82(a)(5)]; and characterize the geochemistry of the subsurface formations.

2.5.3 Site-Specific Data Acquisition

For the Application, the local site characterization was based on data and analyses obtained from public and private sources of information. For the amendment, new analyses of the local geological properties were completed using core samples from the stratigraphic well, which was drilled in [redacted]. Data obtained from the stratigraphic well are outlined in Table 2-1, Tables 2-2a and 2b, and Table 2-3. Table 2-1 presents the wireline logging program, Table 2-2a presents the coring acquisition program, Tables 2-2b and 2-2c present the recovered whole core intervals and rotary sidewall cores with their corresponding formations. Table 2-3 presents the core analysis program. Table 2-4 presents the formation tops at the stratigraphic well and projected tops at the proposed injection wells. Table 2-5 presents formation tops associated with type log wells. Table 2-6a presents XRD mineralogy data obtained at the stratigraphic well, and Table 2-6b presents XRD data from the [redacted].

Claimed as PBI

2.5.4 Site Location and Identification of Injection Intervals and Confining Zones

A site overview map is provided as Figure B-10. This figure presents the regulatorily required data as presented in [40 CFR 146.82(a)] and includes the location of the proposed injection wells, state or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (subsurface and surface), and quarries. The figure also shows, within the AoR, the location and name or number of the injection, producing, abandoned, plugged, dry, deep exploration, or water wells that were identified in a rigorous search of available information. In addition, other surface features including structures intended for human occupancy, state, Tribal and Territorial Boundaries, and roads are presented.

Figures B-11a and 11b present the base map specific to geophysical survey sources and the well data that were utilized for the site characterization and the development of the geologic model for the Project. Figure B-11a presents the local seismic lines parallel and perpendicular to dip, which is also shown on Figures B-36 and B-37. The local cross section locations are also shown in Figure B-11a and B-11b and well locations associated with the cross sections shown

on Figures B-12 and B-13. The cross sections on these maps are presented for orientation purposes.

As presented in the regional geology subsection, the UCCZ overlying the injection zone consists of a thick, muddy interval that includes the Amph 'B' Shale. After reviewing the available data on the Amph 'B' Shale marker, ExxonMobil concluded that a site-specific data collection program was warranted to characterize the physical properties of the Amph 'B' Shale.

The UCCZ layer is shown in the well cross sections in Figures B-12 and B-13 where the fine-grained muddy interval is evident. This layer was confirmed to exist by the analysis of the geophysical logging and sampling results of the stratigraphic well. The potential for vertical flow out of an injection zone was evaluated by comparing the baseline temperature and pressure data at various depths within the injection zone and above the UCCZ, as shown on Figure B-14. Overall, the temperature and pressure measurements reflect the difference in geophysical and mineralogical differences between the intervals of interest as confirmed by the analysis of core data from the stratigraphic well.

The pressure gradient values shown on Figure B-14 were derived from pressure data collected at its respective depth and is calculated by dividing pressure by the depth at which the pressure was measured. A review of Figure B-14 indicated that different pressure regimes are present within the overlying sands, the injection intervals of the [REDACTED], and the underlying sands.

The UCCZ separates the injection zone from the overlying formations. It exhibited a significant measured pressure and temperature differential between the injection zone sands and the overlying sands. The pressure and temperature differentials of approximately 0 [REDACTED]

[REDACTED] Claimed as PBI The magnitude of these differentials is consistent with the shale layering that has been interpreted from petrophysical and mineralogical characterization of log and core data. The UCCZ shales provide a high degree of isolation in the UCCZ and support the conclusion that no significant cross-flow potential of CO₂ and brine from the [REDACTED] to the water-bearing zone above the UCCZ is apparent.

In addition to the UCCZ, the Anahuac Shale offers isolation between the [REDACTED] [REDACTED] Claimed as PBI Due to the low permeability and the pervasive thickness of this shale, vertical cross flow between the [REDACTED] Claimed as PBI is not projected to occur. A pressure gradient differential of up to [REDACTED] Claimed as PBI was observed across the Anahuac Shale, which separates the [REDACTED] Claimed as PBI The temperature gradient was [REDACTED] Claimed as PBI difference for the same intervals. Isolation between the [REDACTED] Claimed as PBI is shown in the pressure data collected in the stratigraphic well and included in Figure B-14 and Appendix B.2.

The LCZ consists of underlying Frio shales that would reduce the potential for any downward migration of formation fluids or CO₂ out of the injection zone. A notable baffle is present at the base of the [REDACTED] Claimed as PBI where the underlying sands have an approximate [REDACTED] Claimed as PBI difference and an approximate temperature difference of [REDACTED] Claimed as PBI shown on Figure B-14.

2.5.5 Top and Bottom Elevations of Injection and Confining Zones

The formation tops at the stratigraphic well and the estimated tops for proposed Project Injection Wells No. 01, No. 02, and No. 03 are provided in Table 2-4. The local structural dip in the area is oriented toward the Gulf of Mexico to the south-southeast. [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]-13 identify the base of the Upper Frio injection zone corresponding to the top of the LCZ.

As shown on the cross sections (Figures B-12 and B-13), the confining zones and injection intervals are laterally continuous throughout the Project area. [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

The cross-section orientations (Figures B-12 and B-13) also illustrate the lateral thickness and continuity of the UCCZ and Anahuac Shale across the AoR. Log data for the stratigraphic well were used for stratigraphic purposes in addition to the original type well selected for this site, [REDACTED] Claimed as PBI, which is located near Injection Well No. 01. The stratigraphic well confirmed the thicknesses of the [REDACTED] Claimed as PBI and interbedded shales. The log data from [REDACTED] Claimed as PBI provided a basis to evaluate formation top elevations, formation thickness, and lithologies from the UCCZ to below the base of the injection zone. Note that while the [REDACTED] Claimed as PBI well extends through the base of the injection zone, it did not extend far into the [REDACTED] Claimed as PBI. Therefore, the [REDACTED] Claimed as PBI was used as the type log for the [REDACTED] Claimed as PBI.

The identified formation tops from the stratigraphic well, [REDACTED] Claimed as PBI, type wells are provided in Table 2-5. Table 2-5 and Figure B-15 presents the [REDACTED] Claimed as PBI type log showing spontaneous potential [REDACTED] Claimed as PBI log data from the top of the UCCZ to the LCZ. [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

Sands are the primary lithology for the injection intervals in both the [REDACTED] Claimed as PBI. These sands contain interbedded shales of varying thicknesses. [REDACTED] Claimed as PBI

Claimed as PBI

In summary, the core data from the stratigraphic well, legacy well logs, literature on regional geology, and seismic data were all used to identify and characterize the injection zone and confining zone depths and properties. Formation thickness values were based on well logs combined with 2D and 3D seismic data interpretation. The net sand maps are sourced from historical well data and confirmed through analysis of data from the stratigraphic well.

An evaluation of the stratigraphic well data confirmed the pre-drill estimates of the net and non-net thickness of the injection and confining zones. These data were combined with the legacy well information to build a 3D geologic model, described below.

2.5.6 Geologic Characteristics of the Injection Zone

The depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection zone are based on lithology and facies changes and were developed for each of the Claimed as PBI to demonstrate how the geological features of each interval align with the target storage volumes [40 CFR 146.82(a)(3)(iii)]. The core descriptions, core photos, mineralogy, core porosity and permeability, and capillary pressure are included in Appendices B.1 and B.2.

Claimed as PBI

While sediment deposition in the Upper Frio and Fleming Formations were both fluvially dominated, the

Claimed as PBI

the AoR.

2.5.6.1 Claimed as PBI

Claimed as PBI

The Fleming Formation Sands have been observed to be fine to medium-grained sands (Galloway et al., 1986). A review of the core descriptions included in Appendices B.1 and B.2 shows the

Claimed as PBI

Claimed as PBI

review of the stratigraphic well mud-logging data indicated that the F

Claimed as PBI

Claimed as
PBI

Claimed as PBI

Claimed as PBI

Table 2-6a presents a summary of these data. The analytical results are presented in Appendix B.2.

¹ Lithological descriptions that were based primarily on mud-logging data are intended to be for qualitative description purposes and provide additional information to supplement the lithological descriptions that were based on the core sample analyses. The reason for this approach is that unconsolidated sands are typically lost with the mud returns and shales and cemented intervals are over-represented in the preserved cuttings.

Mineralogy data from XRD analysis of

Claimed as PBI

Claimed as PBI

Claimed as PBI

PBI

Claimed as PBI

Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01,
No. 02, and No. 03

Claimed as PBI

Claimed as
PBI

2.5.7 Geologic Characteristics of the Confining Zones

The UCCZ occurs immediately above the [redacted]. The geological characteristics of the UCCZ are consistent with the requirements of 40 CFR 146.82(a)(3)(iii) for confining the CO₂ plume and acting to protect USDWs from endangerment. Although not relied upon as the primary confining zone, the Anahuac Shale within the injection zone offers additional CO₂ plume confinement features for the [redacted]. Beneath the [redacted], characterized as a thick marine shale. The following discussion presents the available evidence of the confining properties of the UCCZ, Anahuac Shale, and LCZ. Local well logs, literature sources, and stratigraphic well findings were utilized to assess geologic characteristics of the confining zones.

2.5.7.1 Upper Composite Confining Zone

Claimed as PBI

[REDACTED]

Claimed as
PBI

[REDACTED]

Literature sources cite the potential for these shales to be either Type A or B Seals and will serve as flow barriers, as they are described to have a high degree of impermeability relative to hydrocarbon movement (Sneider, 1995). A Type A Seal estimates that a 35-degree API oil column will be trapped by a shale thickness from greater than or equal to 1,000 ft to less than 5,000 ft. A Type B Seal estimates that a 35-degree API oil column will be trapped by a shale of greater than or equal to 500 ft to less than 1,000 ft (Sneider, 1995).

2.5.7.2 Anahuac Shale

[REDACTED]

Claimed as
PBI

[REDACTED]

Claimed as PBI

2.5.7.3 Lower Confining Zone

F

Claimed as PBI

2.5.8 Local Geologic Structure

T

Claimed as PBI

2.5.8.1 Upper Composite Confining Zone

The UCCZ consists of a fine-grained, muddy interval that includes the Amph 'B' Shale marker.

Claimed as PBI

2.5.8.3 Anahuac Shale

Claimed as PBI

2.5.8.4 [REDACTED]

Claimed as PBI

2.5.8.5 Lower Confining Zone

Claimed as PBI

2.5.9 Seismic Data

Claimed as PBI

2.5.9.1 Velocity Control and Synthetic Seismogram

Claimed as PBI

2.5.9.2 Interpreted Structural Features – Faults

Claimed as PBI

[REDACTED]

[REDACTED]

Claimed as
PBI

[REDACTED]

Claimed as PBI

[REDACTED]

Claimed as
PBI

[REDACTED]

[REDACTED]

Claimed as
PBI

[REDACTED]

[REDACTED]

[REDACTED]

2.5.9.3 Interpreted Structural Features – Fractures

[REDACTED]

Claimed as PBI

[REDACTED]

Claimed as
PBI

2.5.9.4 Uncertainties and Limitations in the Available Data

During the evaluation of the available [Claimed as PBI], some uncertainties and limitations naturally arose regarding the potential for faults and fractures to be present within the AoR that could, potentially, contribute to the vertical transmissivity of CO₂ or displaced formation fluids to the lowermost USDW. As discussed below, ExxonMobil possesses a high degree of confidence in the suitability of the analysis performed and anticipates that additional site characterization should not entail major revisions to the site characterization.

Claimed as
PBI

[REDACTED]

Claimed as PBI

[REDACTED]

2.6 Geomechanics and Petrophysics

The information discussed in this section is from existing sources, such as publications and offset well data. Well data from the [REDACTED] are used to estimate the local stress conditions, elastic moduli, and fracture gradients of the injection and confining zones.

2.6.1 Local Stress Conditions

The World Stress Map is a “global compilation of information on the crustal present-day stress field maintained since 2009 at the Helmholtz Centre Potsdam GFZ German Research Centre for Geosciences.” [REDACTED]

Claimed as PBI

Vertical stress was characterized primarily using bulk density logs from offset wells. [REDACTED]

Claimed as PBI

The minimum horizontal stress, which will be utilized to estimate the fracture gradient, was estimated using two processes: 1) calculate a Poisson’s Ratio using available dipole sonic log data; and 2) use Eaton’s equation to estimate minimum horizontal stress. [REDACTED]

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Dynamic elastic modulus E_{dyn} was calculated using shear wave velocity and the Poisson's Ratio ν as follows.

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

2.6.3 Injection Zone Fracture Gradient Calculation

As discussed in Section 2.6.1 – Local Stress Conditions, Eaton's equation was used, [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

Confining Zone Fracture Gradient Calculation

[REDACTED]

Claimed as PBI

[REDACTED]

Maximum Injection Pressure Calculation

40 CFR 146.88(a) requires that the maximum bottomhole injection pressure must not exceed 90% of the fracture pressure of the injection zone to reduce the potential for existing fractures to propagate during normal operations. [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

2.6.4 Capillary Pressure Data

[REDACTED]

Claimed as PBI

[REDACTED]

threshold pressure (P_{cth}) is the critical pressure at which a nonwetting fluid, in a continuous flowing phase, may displace a wetting-phase fluid from the pore space. For core MICP measurements, this is the pressure at which the percentage of nonwetting mercury volume increases rapidly depending on the rock's pore throat distribution. It implies the capillary force available to hold the buoyancy force of a fluid and is directly proportional to seal quality. MICP P_{cth} for available analog core material was performed using the Thomeer-hyperbola method which enables objective determination of capillary threshold pressure (Thomeer, 1960). P_{cth} is typically a small number for permeable sand but is important to include in the rock property description and simulation model. [REDACTED]

Claimed as PBI

[REDACTED]

Claimed as PBI

Claimed as PBI

Claimed as PBI

[REDACTED]

Claimed as
PBI

[REDACTED]

2.8.3 Net and Non-Net Model

[REDACTED]

Claimed as
PBI

[REDACTED]

[REDACTED]

Claimed as
PBI

[REDACTED]

2.8.4 Net Facies Model

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

Claimed as
PBI

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

2.8.5 Net-to-Gross Model

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

Claimed as
PBI

[REDACTED]

2.8.6 Porosity Model

[REDACTED]

Claimed as
PBI

[REDACTED]

2.8.7 Permeability Model

[REDACTED]
[REDACTED]
[REDACTED]
Claimed as PBI
[REDACTED]

2.8.8 Injection Zone Permeability Test Results

Separate pressure fall-off tests were performed on the [REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
Claimed as
[REDACTED]
[REDACTED]
PBI
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

The fracture gradients obtained from the SRTs are discussed in Section 2.6.2 – Elastic Moduli.

2.8.9 Injection Zone Storage Potential

[REDACTED]
[REDACTED]
[REDACTED]
Claimed as PBI
[REDACTED]

[REDACTED]
Claimed as PBI
[REDACTED]
Claimed as
PBI
[REDACTED]
[REDACTED]

Claimed as PBI

Claimed as PBI

2.8.10 Model Uncertainties

Claimed as PBI

Based on the available data used in the geologic model, these uncertainties are not expected to have a significant impact on the model results and delineation of the AoR. The geologic model will continue to be updated and refined in the pre-operational and operational phases of the Project so that the key geologic features of the Project area continue to be represented in the CO₂ plume and brine pressure front model.

2.9 Assessment of Injection Interval and Confining Zone Geochemical Reactions

The evaluation of the injection zone fluid geochemistry and mineralogy was refined to assess the compatibility of the CO₂ stream with subsurface conditions. The objective of this assessment was to predict how storage and injectivity may be impacted by potential geochemical reactions. The following discussion describes the potential for mineral dissolution and precipitation chemical reactions to occur in the presence of a CO₂-saturated brine. Given the magnitude of new data, results, and findings from this effort, the narrative provided in the Application was re-written to facilitate ease of review and understanding.

2.9.1 Summary of Available Geochemical Data

The geochemical data for fluids in the injection intervals were obtained from the stratigraphic well and compared with the USGS National Produced Waters Geochemical Database (Blondes et al., 2018), as shown in Figure B-68. This database contains information on the likely range of geochemical parameters and the nature of connate formation brines present in the proposed injection intervals. The major cation and anion composition of water samples from the stratigraphic well are provided in Appendix B.4, along with produced water chemistry from Jefferson County, Texas (Blondes et al., 2018).

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as

PBI

Claimed as PBI

The findings of the site-specific models were similar to those of the preliminary models in the Application.

Claimed as PBI

2.9.4 Site-Specific Geochemical Model Methodology

2.9.4.1 Reaction-Path Models

Claimed as PBI

2.9.4.2 Model Input of Brine Chemistry Data

The brine chemistry from the stratigraphic well provided in Table 2-23 and Appendix B.4 was used as a starting point for the reaction-path models for each of the modeled formations.

Claimed as PBI

2.9.4.3 Model Input: Formation Mineralogy

The representative mineralogy for each formation used in the reaction-path models is provided in Table 2-24.

Claimed as PBI

[REDACTED]

Claimed as PBI

2.9.5 Simulating Initial Brine-Mineral Equilibration and CO2 Reactions

[REDACTED]

Claimed as
PBI

[REDACTED]

2.9.6 Summary of Site-Specific Geochemical Model Results

The geochemical models were used to simulate the potential for significant mineral precipitation and dissolution to occur in the injection and confining intervals. Figures B-69 (a, b, and c), B-70, B-71, and B-72 present the geochemical modeling results for the [REDACTED] respectively. The results are plotted as change versus time for these relationships:

- [REDACTED]

Claimed as PBI

The following discussion presents the model results for each interval.

2.9.6.1 Geochemical Model Results for UCCZ

[REDACTED]

Claimed as PBI

[REDACTED]

2.9.6.2 Geochemical Model Results for [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

2.9.6.3 Geochemical Model Results for [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

Claimed as
PBI

[REDACTED]

Claimed as PBI

[REDACTED]

2.9.7 Summary of Mass Transfer Potential Resulting from CO2 Injection

The following findings were apparent from the review of the [REDACTED]

[REDACTED]

Claimed as
PBI

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

2.9.8 Potential Uncertainty in Geochemical Reaction Path Model

A review of the input data, site characterization data, geochemical model performance identified the potential for uncertainty to influence the model results. As outlined below, steps were taken to reduce the potential for the uncertainty in site characterization and modeling approach to impact the overall findings of the geochemical model.

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

**Claimed as
PBI**

[REDACTED]

2.9.9 Summary of Predicted Geochemical Reactions and Potential for USDW Endangerment

A series of geochemical scenarios were modeled to provide predictions on the compatibility of the injection and sealing intervals of the AoR with the injection of CO₂ and the subsequent CO₂-saturated brine. These site-specific models used fluid chemistry from the stratigraphic well that is consistent with produced water chemistries in the region and XRD mineralogical data representative of the formations of interest. [REDACTED] models demonstrated that during the interaction of the CO₂-saturated brine and the formations of interest, both precipitation and dissolution of minerals is predicted to occur at a magnitude that does not significantly alter the total mineral volume of the system. As such, no significant change in mineral or pore-space volume in the formations was predicted by the models.

2.10 Hydrogeology

The Project site is in northwestern Jefferson County, overlying the Gulf Coast Aquifer. The Gulf Coast Aquifer is a major aquifer designated by the Texas Water Development Board (TWDB) extending from the eastern border with Louisiana to the United States border with Mexico. The maximum total sand thickness of the Gulf Coast Aquifer ranges from approximately 700 ft in the south to approximately 1,300 ft in the north. According to George et al. (2011), freshwater saturated thicknesses average approximately 1,000 ft. The Gulf Coast Aquifer is used for municipal, industrial, and irrigation purposes.

2.10.1 Identification of USDW

Claimed as PBI

[REDACTED]

Claimed as
PBI

[REDACTED]

2.10.2 Total Dissolved Solids and Groundwater Flow Direction

Multiple studies of the Gulf Coast Aquifer hydrogeology have been performed and a considerable number of studies have been conducted regarding the formation brine salinity trends (i.e., TDS) with depth. Baker (1978) published multiple cross sections characterizing groundwater salinity with depth in the Gulf Coast Aquifer and identified an estimated depth of the occurrence of groundwater with TDS concentrations below 3,000 mg/L. Young et al. (2016) has produced an extensive evaluation of water quality in the Gulf Coast Aquifer and mapped groundwater quality with depth for several TDS intervals. These include what the authors describe as “fresh,” “slightly saline,” “moderately saline,” “very saline,” and “brine,” at upper TDS values of 1,000, 3,000, 10,000, 35,000 mg/L, and above, respectively.

Figure B-74 presents a general hydrogeologic cross section in the northern portion of the Gulf Coast Aquifer, which represents the configuration of these units near the Project area. Figure B-74 also presents the maximum depth of freshwater (defined as less than 1,000 mg/L TDS) based on groundwater sampling in five-by-five mile grid blocks by Young et al. (2016). [REDACTED]

Claimed as PBI

Figure B-75 presents the estimated depths to the base of fresh water (less than 1,000 mg/L TDS) and estimated depths to the base of 3,000 mg/L TDS groundwater in the Gulf Coast Aquifer. These data are based on water quality calculations by Young et al. (2016). Near the site, these depths range between 250 to 500 ft (fresh water) and 1,000 to 1,500 ft (less than 3,000 mg/L TDS; Figure B-75). [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

2.10.3 Evaluation of the Lowermost USDW

This section presents a site-specific evaluation of water quality with depth, the identification of the lowermost USDW, and distance from the lowermost USDW to the top of the injection zone within the AoR. Three lines of evidence were used to assess water quality with depth in the vicinity of the site. Each line of evidence is presented below. [REDACTED]

Claimed as PBI

[REDACTED]

2.10.3.1 Literature Review

[REDACTED] presents estimated depths to the base of groundwater with TDS concentrations less than 10,000 mg/L (or base of the lowermost USDW defined by 40 CFR 146.3) and for brines that contain less than 35,000 mg/L TDS, based on water quality calculations by Young et al. (2016). [REDACTED]

Claimed as PBI

[REDACTED] salinity levels were observed to continue to rise or remain steady with depth, and do not exhibit salinity levels less than 35,000 to 50,000 mg/L (Young et al., 2016).

[REDACTED]

Claimed as PBI

[REDACTED]

2.10.3.2 Water Quality Calculations

Water quality calculations were conducted to characterize water quality at depth in the Gulf Coast Aquifer and delineate USDW depths near the AoR. The data were sourced from published literature and studies of the Gulf Coast Aquifer and imaged well logs from the Railroad Commission of Texas, as well as the TWDB Brackish Resources Aquifer Characterization System. Water quality calculations presented in this section are based on

available geophysical data (i.e., wireline log data) from oil and gas wells near the AoR.

[REDACTED]

Claimed as
PBI

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

Claimed as PBI

[illegible]

Claimed as PBI

[REDACTED]

Claimed as
PBI

[REDACTED]

2.11 Seismic Risk and Fault-Slip Potential for AoR

The Project area is reported by USGS to be of very low seismic hazard (low peak acceleration [4 to 6%g] seismic hazard, i.e., a 2% chance in 50 years of peak ground acceleration at 4 to 6%g, acceleration of gravity). T [REDACTED]

Claimed as PBI In addition, there have been no recorded earthquakes in the vicinity of the Project area since 1973, based on a search of the USGS national earthquake database. The injection pressures will be limited to values that reduce the potential for the initiation or propagation of fractures. No induced seismicity is expected to occur under the proposed permit conditions. The following evaluations were conducted to provide a site-specific technical evaluation of the seismic risk within the AoR.

[REDACTED]

Claimed as
PBI

[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
Claimed as

PBI
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

[REDACTED]
[REDACTED]
[REDACTED]
Claimed as

PBI
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]

Based on the seismic history of the Project area and the conforming pore pressure calculations, the potential for induced seismicity from CO₂ injection at the Project area is not a significant risk. Appendix I includes additional information of the methodology used to estimate the fault-slip potential within the AoR.

2.12 Site Suitability

The purpose of this subsection is to present a summary of the geologic site characterization information, as required for the Underground Injection Control Program Director to evaluate site suitability. The Project area is suitable for CO₂ injection into the proposed injection [REDACTED] **Claimed as PBI** [REDACTED]. The sands within these formations exhibit high porosity and permeability that are ideal for CO₂ storage and are “of sufficient areal extent, thickness porosity and permeability to receive the total anticipated volume of the CO₂ stream” [40 CFR 146.83(a)(1)]. Both the UCCZ and Anahuac Shale are thick, continuous sealing intervals across the AoR and are sufficient to “contain the injected CO₂ stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone” [40 CFR 146.83(a)(2)]. The following site features substantiate these conclusions.

2.12.1 Local Geology and Injection Interval Suitability

The Project area is in the Houston Embayment of the Gulf Coast Basin. [REDACTED]

Claimed as PBI

[REDACTED] the Fleming stratigraphic intervals were deposited in a fluviially dominated delta system. Hyper-subsidence and collapse with periodic deposition of slope mudstones form transgressive shales are observed at the site. [REDACTED]

Claimed as

PBI

2.12.2 Summary of Storage Capacity

Claimed as PBI

Claimed as PBI

2.12.3 Summary of Confining Zone(s) Suitability

Claimed as PBI

Claimed as PBI

Claimed as PBI

2.12.4 Summary of CO₂ Stream Compatibility and Suitability

A series of geochemical reaction scenarios were modeled using information collected from the stratigraphic test well to generate insights into how the subsurface confining and injection formations could respond to CO₂ sequestration.

Claimed as PBI

TABLES

Claimed as
PBI

Claimed as PBI

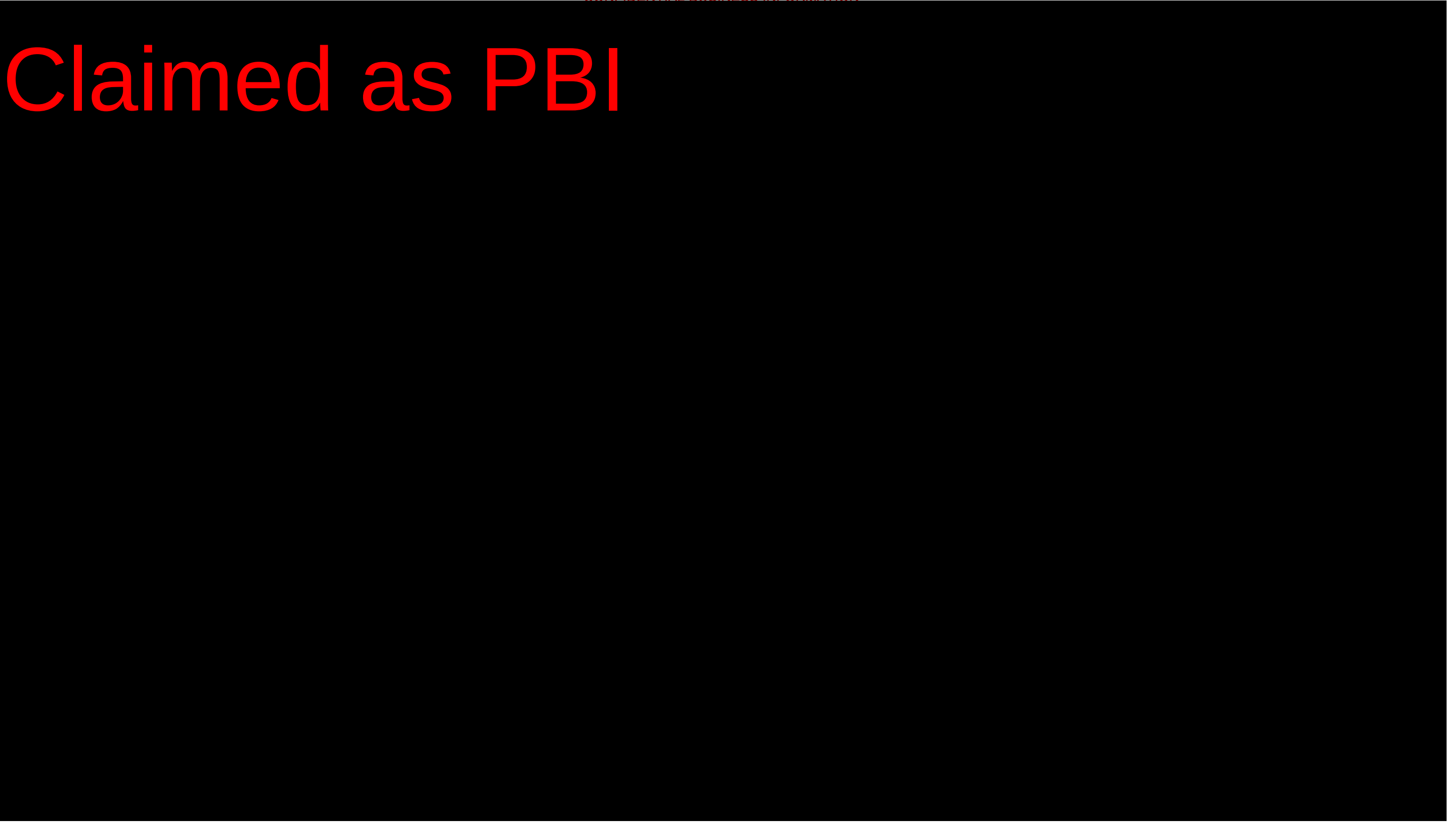


Claimed as
PBI

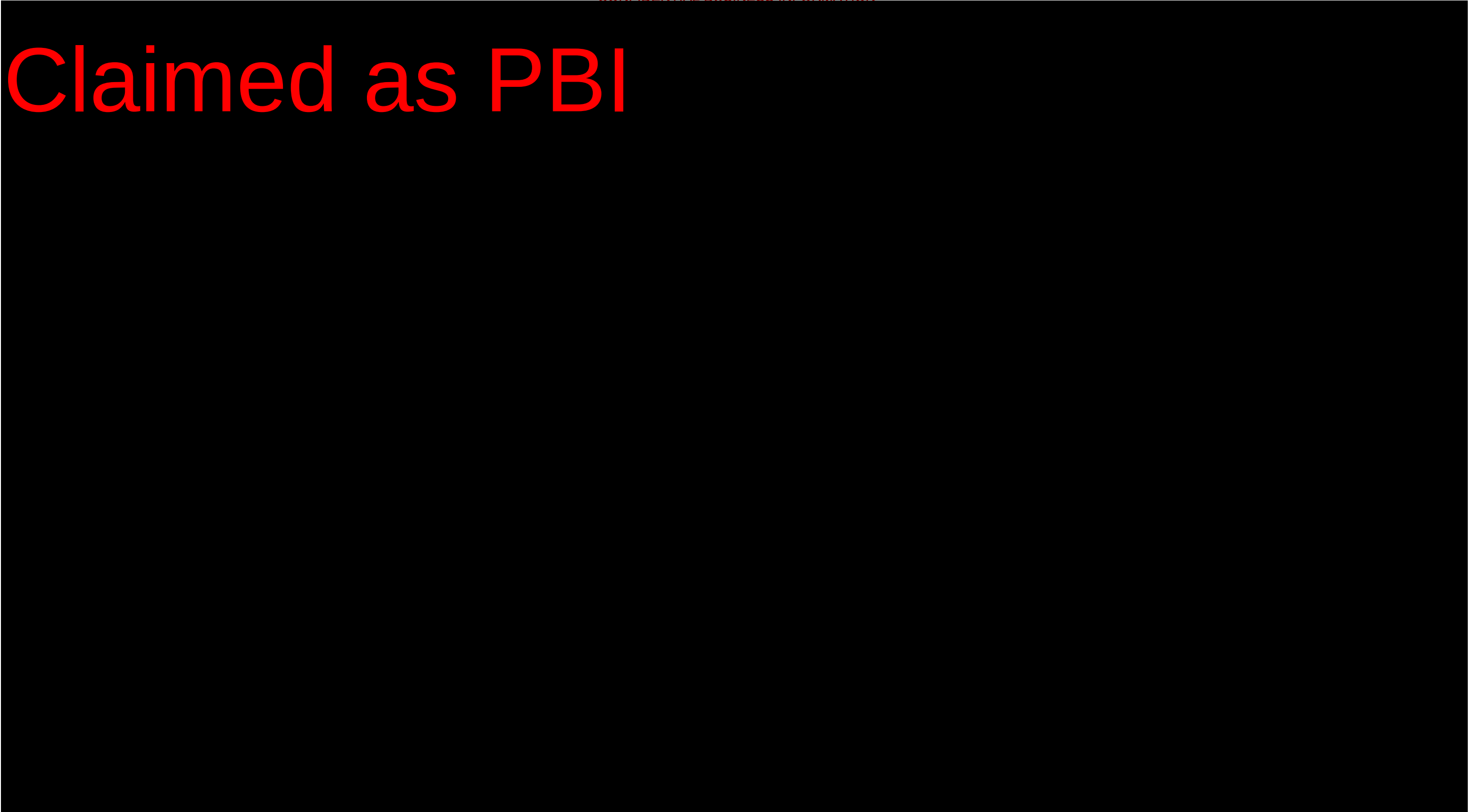
Claimed as PBI

-Page Intentionally Left Blank-

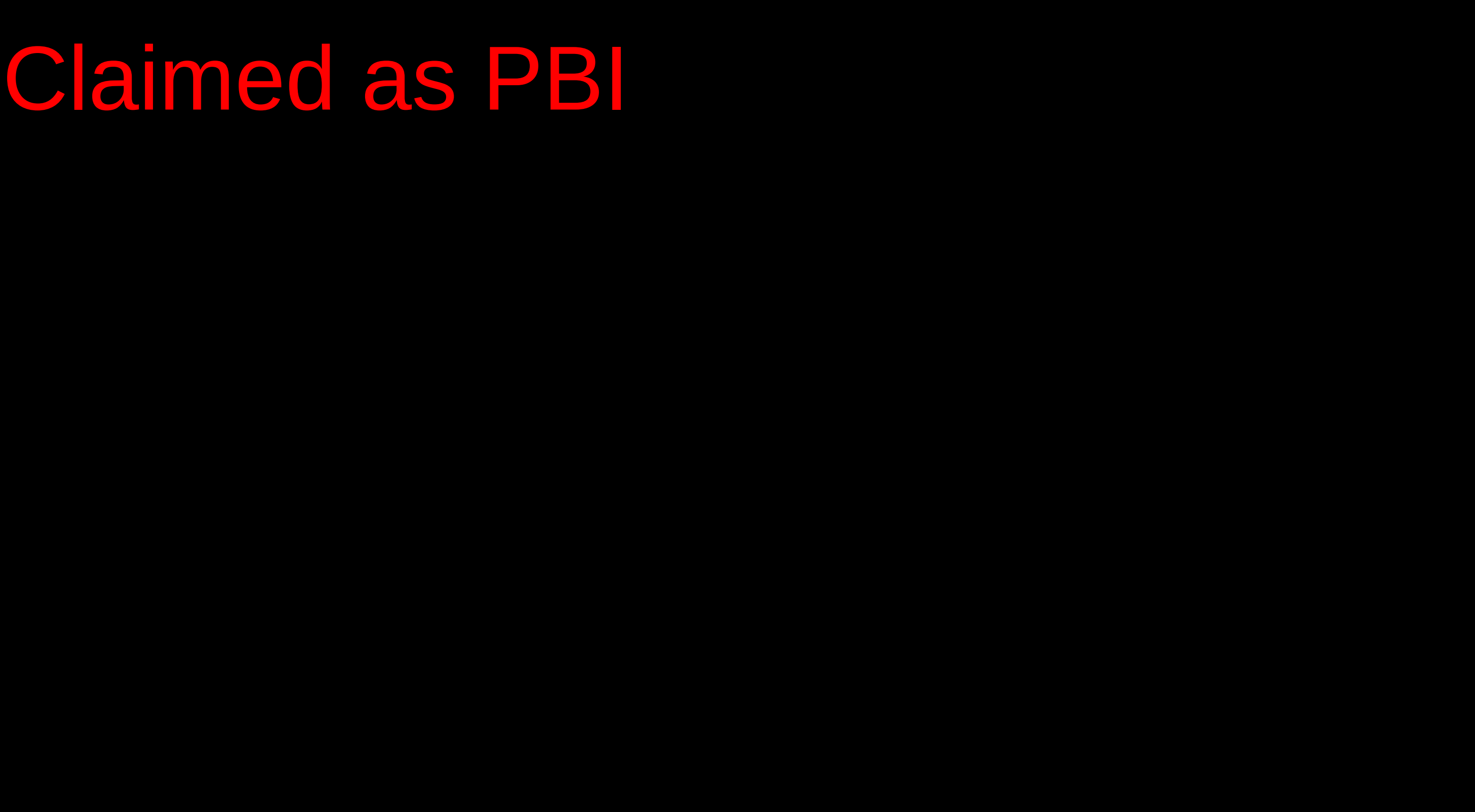
Claimed as PBI



Claimed as PBI

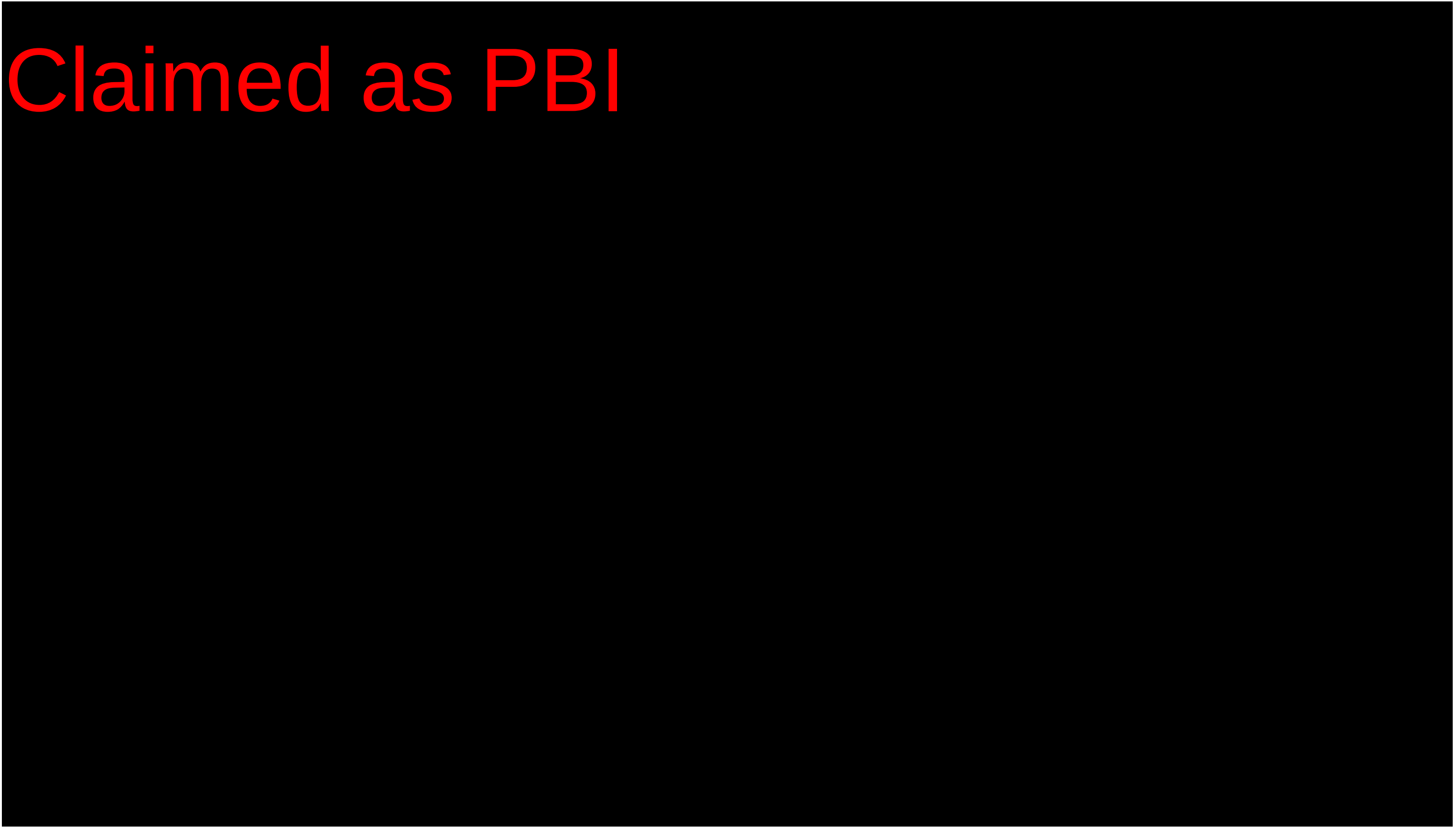


Claimed as PBI



Claimed as PBI

Claimed as PBI



Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI



Underground Injection Control – Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN

Rose Carbon Capture and Storage Project
Jefferson County, Texas
ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2025

SECTION 3 – AREA OF REVIEW AND CORRECTIVE ACTION PLAN**TABLE OF CONTENTS**

3.0 Area of Review and Corrective Action Plan	7
3.1 Objectives	7
3.2 Facility Information.....	8
3.3 Derivation of Input Parameter Values for Geologic Properties	9
3.3.1 Porosity and Permeability	9
3.3.2 Rock Compressibility	10
3.3.3 Relative Permeability	11
3.3.4 Capillary Pressure	13
3.3.5 Fluid Pressure.....	14
3.3.6 Temperature	15
3.3.7 Formation Compressibility.....	16
3.3.8 Initial Saturation	16
3.4 Derivation of Input Parameter Values for Fluid Properties	17
3.4.1 Fluid Composition	17
3.4.2 Fluid Density and Viscosity	17
3.4.3 Fluid Compressibility.....	20
3.5 Derivation of Input Parameter Values for Chemical Properties	21
3.5.1 Aqueous Solubility	21
3.5.2 Solubility in Carbon Dioxide	22
3.6 Model Design and Input Parameters	22
3.6.1 Model Background.....	22
3.6.2 System Orientation and Simulation Controls for Model	23
Claimed as PBI	
3.6.4 Fracture Pressure and Fracture Gradient.....	30
3.6.5 Boundary Conditions.....	33
3.7 AoR Delineation Based on Model Results	33
3.7.1 Extent of CO ₂ Plume	33
3.7.2 Delineation of the Critical-Pressure Front.....	37
3.8 Stages of Model Development	43
3.9 Corrective Action Plan and Schedule.....	43

3.9.1	Data Acquisition and Evaluation of Artificial Penetration Information.....	44
3.9.2	Corrective Action Plan for Artificial Penetrations	55
3.9.3	Corrective Action Sequence Plan.....	60
3.9.4	Site-Specific Review of Corrective Actions.....	62
3.9.5	Stratigraphic Well P&A Plans	63
3.9.6	Plan for Site Access.....	64
3.10	AoR Reevaluation Plan and Schedule.....	65
3.10.1	Frequency of AoR Reevaluation	65
3.10.2	Content of the AoR Reevaluation.....	65
3.10.3	Conditions Warranting AoR Reevaluation	65

List of Tables

Claimed as
PBI

Claimed as PBI

List of Figures

Claimed as
PBI

Claimed as PBI

-Page Intentionally Left Blank-

- Predict the extent of the CO₂ plume and pressure front, which form the basis for the AoR using computational modeling and identify all wells that require corrective action [40 CFR 146.84(c)];
- Provide a plan to perform the required corrective action on artificial penetrations in the AoR [40 CFR 146.84(d)] that could threaten USDW;
- Support the development of effective monitoring strategies for the Testing and Monitoring Plan by identifying the locations where groundwater quality or pressure monitoring should be performed;
- Help direct emergency response planning by identifying potential vulnerable areas within or near the AoR that could require consideration when implementing an emergency response;
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AoR [40 CFR 146.84(f)];
- Provide a guide for periodic AoR reevaluations to informed site management and monitoring over the lifecycle of the injection Project [40 CFR 146.84(e)]; and
- Retain modeling inputs and data used to support AoR reevaluations for 10 years [40 CFR 146.84(g)].

3.2 Facility Information

The following facility information is provided to specify the names and locations of the three injection wells.

Geologic Sequestration Project name: ExxonMobil Low Carbon Solutions Onshore Storage LLC – Rose Carbon Capture and Storage Project

Injection Well Information:

Well Name and Number

Claimed as PBI (Rose CCS Project Injection Well No. 01)

County

Jefferson

Location (RR D, S, A)

Latitude / Longitude (NAD83)

API

Claimed as PBI

Well Name and Number

Claimed as PBI (Rose CCS Project Injection Well No. 02)

County

Jefferson

Location (RR D, S, A)

Latitude / Longitude (NAD83)

API

Claimed as PBI

Well Name and Number

Claimed as PBI (Rose CCS Project Injection Well No. 03)

County

Jefferson

Location (RR D, S, A)

Latitude / Longitude (NAD83)

API

Claimed as PBI

3.3 Derivation of Input Parameter Values for Geologic Properties

ExxonMobil recognizes that parameter values for the prediction of the AoR are to be based on site-specific data to the extent possible. A stratigraphic well was completed and core samples were collected from the well to obtain the necessary site geologic characterization data for the CO₂ plume model. Additionally, where appropriate, the parameter values were estimated from standard values published for similar rock types and relationships in the scientific literature. As outlined below, ExxonMobil derived initial estimates of formation intrinsic permeability, porosity, relative permeability, compressibility, fluid viscosity, and fluid density from the available information, with emphasis on the available stratigraphic well data and test results, as appropriate.

The site-specific characteristics that make the Project site ideal for carbon sequestration are described in Section 2.12 of Section 2 – Site Characterization. In summary, the sands of the Claimed as PBI exhibit high porosity and permeability that are ideal for CO₂ storage and are “of sufficient areal extent, thickness porosity and permeability to receive the total anticipated volume of the carbon dioxide stream” [40 CFR 146.83(a)(1)]. Both the Claimed as PBI are thick, continuous sealing intervals across the AoR and are sufficient to “contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressure and volumes without initiating or propagating fractures in the confining zone” [40 CFR 146.83(a)(2)].

3.3.1 Porosity and Permeability

Porosity information was obtained from Claimed as PBI well logs within the geologic model of the area of interest, which includes the AoR and a significant area surrounding the AoR. This information was utilized to generate a three-dimensional geologic model for the Project area. Most of the porosity data were provided based on compressional sonic data. Some bulk density data were also used to inform the estimates of porosity for the formations. Porosity and permeability data were gathered from the stratigraphic well Claimed as PBI and incorporated into the geologic model for the Project area.

Permeability was modeled based on the results of the total porosity estimate calculations. Separate porosity-permeability transforms were developed for the Claimed as PBI

Claimed as PBI

The results presented below reflect a site-specific set of properties that extend beyond the predicted extent of the CO₂ plume and the AoR boundary. The results of the model continue to demonstrate, as did the initial model effort, how the sequestration of CO₂ is protective of USDWs.

3.3.2 Rock Compressibility

Based on the rock compressibility measurements for the sandstone samples collect at the stratigraphic well, an average value of [REDACTED]

Claimed as PBI

[REDACTED] These values are reasonably consistent with the available literature values. Figure 3-1 provides a literature-based relationship between pore volume compressibility and initial porosity. The average rock compressibility values derived from various cored intervals of the stratigraphic well are demonstrated in Figure 3-2. These values are consistent with the literature-based ranges described in Figure 3-1.

Figure 3-1: Pore Volume Compressibility as a Function of Initial Porosity

Claimed as
PBI

Claimed as PBI

3.3.3 Relative Permeability

Relative-permeability curves were generated based on research of analogous depositional environments. Traditional core testing has difficulty accurately measuring the endpoints of the curves, resulting in high irreducible water saturations and low CO₂ endpoints [REDACTED] (REDACTED). In drainage CO₂-brine relative-permeability experiments, as water saturation decreases, capillary forces become larger [i.e., capillary pressure (P_c)] and increase rapidly in the approach to the irreducible water saturation. During the experiment, the increase in capillary forces limits further reduction in water saturation (i.e., the viscous force is too small relative to the capillary force). This causes the experimental relative-permeability measurements to end at water saturations higher than the actual irreducible water saturation. [REDACTED]

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed
as PBI

Claimed as PBI

Claimed as PBI

[REDACTED]
[REDACTED]
[REDACTED]
Claimed as PBI
[REDACTED]

[REDACTED]
Claimed as PBI

[REDACTED]
Claimed as PBI

3.3.4 Capillary Pressure

Initial estimates of capillary pressure were estimated using capillary pressure functions by the

[REDACTED]
Claimed as PBI

[REDACTED]
Claimed as PBI

[REDACTED]
[REDACTED]
Claimed as PBI
[REDACTED]

[REDACTED]
Claimed as PBI

[REDACTED]
Claimed as PBI
[REDACTED]

Claimed
as PBI

3.3.5 Fluid Pressure

The average formation fluid pressure gradient was derived from [REDACTED] formation pressure data points acquired from the stratigraphic well. The pressure gradient value is [REDACTED] Claimed as PBI [REDACTED] represented in Figure 3-5. This original reservoir pressure gradient was based data points collected from [REDACTED] Claimed as PBI [REDACTED] and was considered representative of sand intervals to be used for injection. The measured site-specific values are consistent with expected values obtained from available literature, which reported an average value of approximately [REDACTED] Claimed as PBI [REDACTED]

Claimed as PBI

3.3.6 Temperature

Based on data collected from the stratigraphic well, the temperature gradient is [REDACTED] [REDACTED] Mean surface temperature was assigned as [REDACTED] yielding an original temperature of [REDACTED] in the reservoir model at a reference depth of [REDACTED]. The original temperature was assigned to be consistent with this temperature and the temperature gradient throughout the model domain. The temperature gradient is represented in Figure 3-6.

Claimed as
PBI

3.3.7 Formation Compressibility

Total formation compressibility includes rock compressibility (Section 3.3.2) and fluid compressibility (Section 3.4.3). Both are accounted for during simulation of CO₂ injection.

3.3.8 Initial Saturation

Claimed as PBI

3.4 Derivation of Input Parameter Values for Fluid Properties

3.4.1 Fluid Composition

Fluid samples were collected from the stratigraphic well and analyzed for fluid composition. The results of laboratory analyses for total salinity are summarized in Table 3-2. The simulation model was updated with average salinity of [redacted] at reference depth of [redacted] A detailed fluid analysis is presented in Section 2.9 of Section 2 – Site Characterization.

Claimed as PBI

Claimed as PBI.

3.4.2 Fluid Density and Viscosity

Claimed as

PBI

Claimed as PBI

Claimed as PBI

Figures 3-7 and 3-8 illustrate density variation for CO₂ and brine vs. depth. [REDACTED]

Claimed as PBI

Claimed as
PBI

Claimed as PBI

3.4.3 Fluid Compressibility

Claimed as PBI

Claimed as PBI

Claimed as
PBI

3.5 Derivation of Input Parameter Values for Chemical Properties

3.5.1 Aqueous Solubility

CO₂ can dissolve in water and dissolved CO₂ is considered permanently sequestered in the saline aquifer. Therefore, dissolution is an important sequestration mechanism.

Claimed as PBI

Claimed as PBI

Claimed as
PBI

3.5.2 Solubility in Carbon Dioxide

Claimed as PBI

3.6 Model Design and Input Parameters

The model design is based on the use of state-of-the-art computer simulation tools with a proven record of modeling multiphase flow.

Claimed as PBI

3.6.1 Model Background

Schlumberger's Petrel™ Software was chosen to create a detailed geologic model for the Project. This state-of-the-art software is used worldwide and combines information from logs and seismic data to build a sophisticated representation of the underground reservoir. The Petrel™-developed geologic model incorporates the geologic layers of the site described in the Section 2 – Site Characterization, including three targeted injection zones within the

Claimed as PBI

Section 2.

The geologic model developed in Petrel™ was used as an input into the Schlumberger Eclipse™ numerical reservoir simulator. Eclipse™ is a widely recognized tool used for modeling both compositional and unconventional reservoirs. The simulator uses advanced computational methods and equation-of-state algorithms to evaluate compositional, chemical, and geochemical processes to produce a reliable simulation for CCS. The software has modules and options specifically intended to allow the study of CCS injection activities, can handle large data sets and multiple grids, and offers various tools for data management, visualization, and uncertainty analysis.

3.6.2 System Orientation and Simulation Controls for Model

[REDACTED]

Claimed as PBI

[REDACTED]

The initial pore pressure and fracture pressure gradients were calculated to be [REDACTED] respectively. The estimated temperature gradient is [REDACTED] which was calculated from measurements made at the stratigraphic well. Salinity was estimated to range from [REDACTED] based on measurements from the stratigraphic well.

Claimed as PBI

Claimed as PBI

3.6.3

Claimed as PBI

Of the model refinements made for the Amendment, the most critical were related to the following changes in the model input parameters compared with the Application:

1. [REDACTED]

Claimed as PBI

Three primary constraints were imposed to limit plume movement: (1) the maximum injection rate [REDACTED] (2) a maximum bottomhole pressure (BHP) gradient of [REDACTED] [REDACTED] and (3) an injection period of [REDACTED] for all three injection wells. A skin factor of 10 was applied to the wellbore to simulate potential formation damage that may occur over time. This assumption was considered when calculating the wellhead pressure. The permeability-thickness data obtained from the stratigraphic well and used in the model resulted in an [REDACTED]

Claimed as PBI Injection Wells No. 1, 2, and 3 were simulated at a maximum injection rate of 1.67 MMta, an increase [REDACTED] in the Application. Pressure was not a limiting factor defining the model AoR boundary projections. The [REDACTED]

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as
PBI

Claimed as PBI

Claimed as PBI



Claimed as
PBI

3.6.4 Fracture Pressure and Fracture Gradient

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

3.6.5 Boundary Conditions

ExxonMobil selected the boundary condition for the model domain that describes the fluid flow rates and/or pressures at the edges of the model domain and at the location of injection wells.

[REDACTED]

Claimed as PBI

[REDACTED]

3.7 AoR Delineation Based on Model Results

3.7.1 Extent of CO2 Plume

The areal grid block size in the model was selected to optimize model runtimes, limit grid distortion effects, and allow for sufficiently accurate contouring of plume extent over a distance of multiple miles. The operational and geologic input parameters were used in the Eclipse™ model to generate projections of plume and pressure migration versus time. [REDACTED]

Claimed as PBI

[REDACTED]

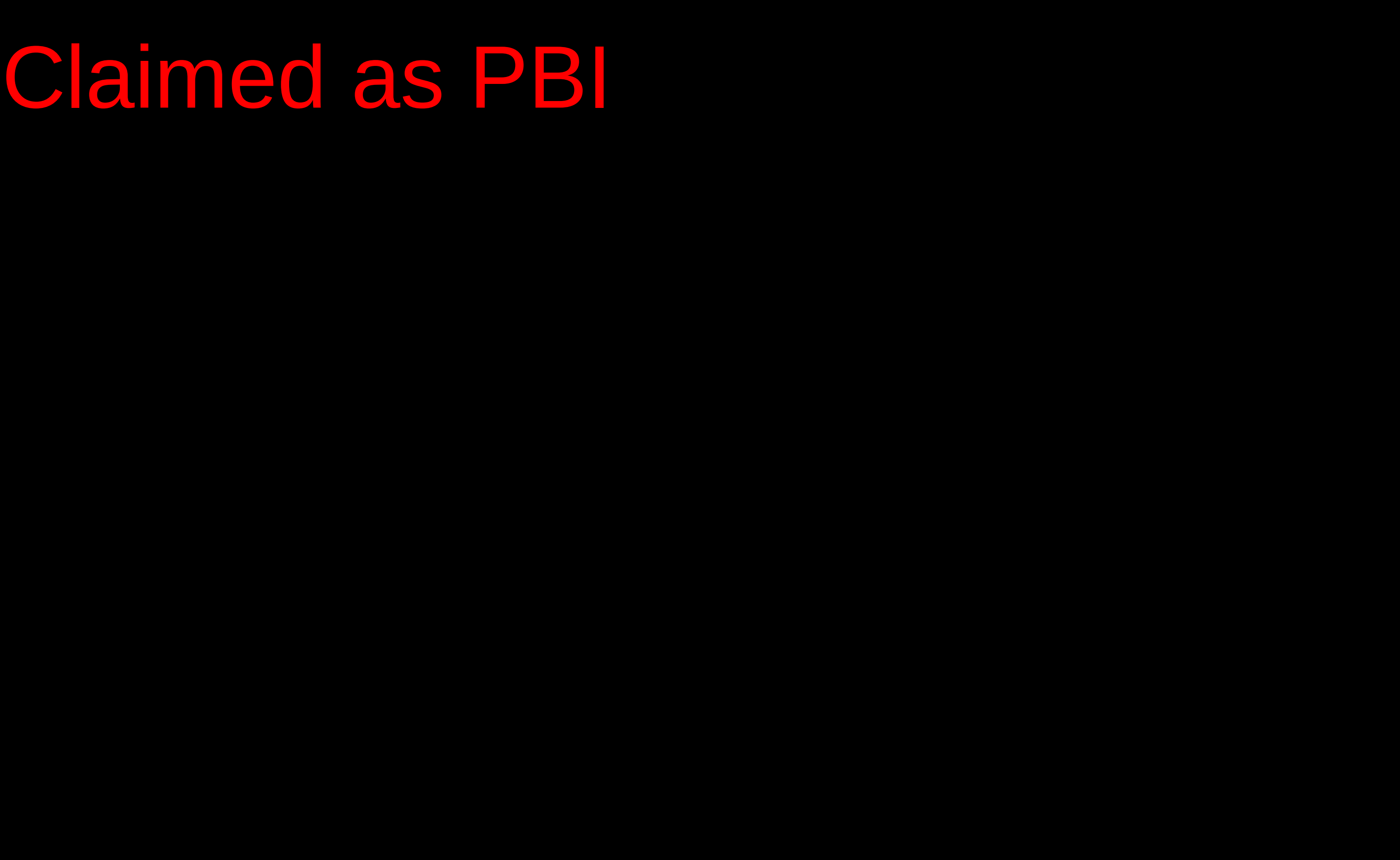
Claimed as PBI

Claimed as PBI

[REDACTED]

-Page Intentionally Left Blank-

Claimed as PBI



-Page Intentionally left Blank-

Claimed as PBI

Claimed as
PBI

The update model demonstrates improvement in the Project to sequester an

Claimed as PBI

3.7.2 Delineation of the Critical-Pressure Front

In accordance with 40 CFR 146.84, the AoR was delineated by the critical-pressure front created by the injection of CO₂ into the injection intervals. Critical pressure is the increase in reservoir pressure that has a potential to create crossflow of brine from the injection zone into the lowermost USDW, assuming the presence of a hypothetical bridging conduit such as an unplugged borehole. The first step to predict the pressure front of interest is to calculate the critical pressure for each completion stage. Once critical pressure is estimated, a numerical simulation is used to predict the size and shape of the critical-pressure front defined by this pressure contour.

3.7.2.1 Critical-Pressure Calculations

The methodology for defining the critical pressure was sourced from Nicot Claimed as PBI which is referenced in the EPA guidance for calculations based on displacing fluid initially present in a borehole.

Claimed as PBI

For the purposes of the critical-pressure calculations, the base of the USDW within the AoR was assumed to be [REDACTED]

Claimed as PBI

[REDACTED] and within the overall range of [REDACTED] measured depth KB described in Section 2 – Site Characterization. The critical pressure was calculated for each completion phase of each injection well, with the top of the effective injection interval perforations ranging from depths of [REDACTED] Based on the site-specific fluid samples from the stratigraphic well, the total dissolved solids (TDS) of the brine was observed to range from [REDACTED]

Claimed as PBI

[REDACTED] reservoir pressure gradient if the reservoir was originally in hydrostatic equilibrium with a column of this brine from the depth of the reservoir to surface. The fluid within the USDW was assumed to be fresh water with a fluid pressure gradient of [REDACTED] Inputs for an example critical pressure calculation (Rose CCS Project Injection Well No. 01; [REDACTED]) are provided in Table 3-14.

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as
PBI

3.7.2.2 AoR Delineation

The maximum areal extents of both the CO₂ plume and the critical-pressure front were used to delineate the AoR at any time interval or depth. The larger extent of either CO₂ saturation or critical-pressure rise was used to define the AoR boundary.

Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

3.8 Stages of Model Development

The stages of development for the CO₂ plume and pressure-front model started with pre-operational phase data and industry standards to predict the AoR boundary. The geomodel and reservoir model rely on these data and on industry standard correlations for the assignments of properties based on site-specific conditions derived from analysis of stratigraphic well data. Physical rock property distributions assigned to the model based on geostatistics have been analyzed and are consistent with the stratigraphic well test results for model grids in the vicinity of the stratigraphic well. No data from historical or nearby injection operations was readily available to support the AoR delineation process.

The following objectives were achieved for the pre-operational phase of the model:

1. Verify that the AoR was based on relevant existing and new information and identify where new information from the stratigraphic well supports the previous approaches and assumptions used in the model;
2. Align the updated conceptual/geologic model and model inputs with pre-operational testing results and assess how the stratigraphic well addressed previous data gaps and uncertainties associated with the prior AoR delineation;
3. Assess how the updated AoR model reasonably and accurately represent the geologic and operational systems, and yields information necessary to delineate the AoR; and
4. Confirm that conservative and reasonable methods were used to delineate the AoR and protection of USDW.

Looking forward to the operational phase of the project, updates will be made to the model for calibration purposes. The model calibration procedures will likely focus on the parameters that have been identified during the pre-operational modeling effort as the most sensitive parameters during sensitivity analyses. The calibration process is intended to be an iterative process, with updates to the geomodel and input parameters, to achieve an acceptable agreement between model predictions and the collected testing and monitoring data.

3.9 Corrective Action Plan and Schedule

Consistent with 40 CFR 146.84, the primary objective of this Corrective Action Plan is to identify the potential risk for loss of CO₂ or brine containment through artificial penetrations of the UCCZ and to specify corrective actions that would be taken to restore the integrity of the UCCZ, if needed. ExxonMobil undertook a thorough investigation of artificial penetrations within and immediately adjacent to the AoR. Public and private databases were searched, historical aerial photographs were reviewed, [REDACTED]

Claimed as PBI

Claimed as PBI

Claimed as PBI

3.9.1 Data Acquisition and Evaluation of Artificial Penetration Information

- The Railroad Commission of Texas (RRC) GIS Database;
 - The Texas Water Development Board;
 - Texas Commission on Environmental Quality UIC Central File Room database;
 - Brackish Resources Aquifer Characterization System;
 - Database for underground mines and quarries (U.S. Geological Survey Mine Related Features and U.S. Geological Survey Mineral Resources);
 - State- or EPA-approved subsurface cleanup sites; and
 - [REDACTED]
- Claimed as PBI [REDACTED]

- Historical aerial photograph reviews for the identified artificial penetration locations;
- A physical record request was made to the RRC, and the available documents were reviewed;

Claimed as PBI

Using a combination of the data above, a tabulation of identified artificial penetrations within the AoR has been created and is summarized in Table 3-16. The identified artificial penetrations can be found on Figure 3-19. Available records for the identified artificial penetrations can be found in Appendix C.

Claimed as PBI

Claimed as PBI

3.9.1.1 Review of Historical Aerial Photographs

ExxonMobil conducted a review of readily available historical aerial photographs for selected legacy wells to assess well location and completion dates. [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

**Claimed as
PBI**

Claimed as PBI

Claimed as
PBI

Claimed as PBI

Claimed as
PBI

3.9.1.2 Physical Records Review

For wells within the AoR, ExxonMobil obtained copies of physical records for [REDACTED]

Claimed as PBI

3.9.1.3 Aeromagnetic Survey

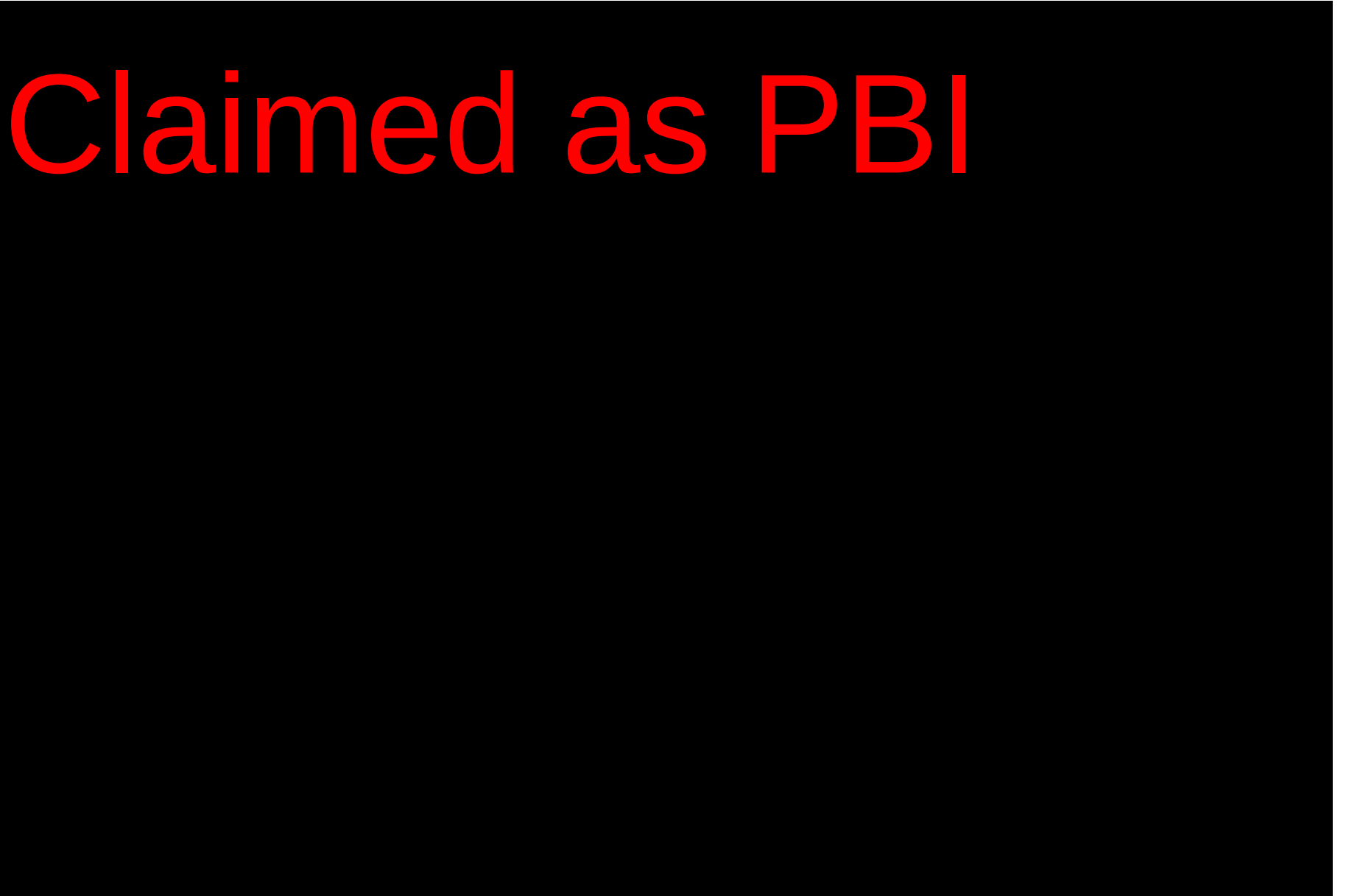
Due to the age of well development in the area, additional data collection was conducted in selected portions of the AoR, wherein additional insight into well locations or details was required to improve accuracy. [REDACTED]

Claimed as
PBI

Claimed as PBI

Claimed as
PBI

Claimed as PBI



[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

Claimed as

PBI

[REDACTED]

Claimed as PBI

3.9.1.4 Review of Abandoned Well Plugging Records

ExxonMobil conducted an evaluation of the information available for the artificial penetrations listed in Table 3-16. The list of topics reviewed included:

- Well depth and completion;
- Well drilling date;
- Well abandonment date;
- Open hole or cased hole identification;
- Location of reported plugs;
- Casing and cementing records;
- Records of mechanical integrity tests or logs performed; and
- Well deviations.

Claimed as PBI

Claimed as PBI

3.9.1.5 Summary of Artificial Penetrations Tabulation

ExxonMobil conducted a thorough assessment of the potential for artificial penetrations to be present within the AoR. Wells and boreholes completed above the UCCZ were determined to pose no hypothetical risk to function as a vertical conduit from the injection zone. For those artificial penetrations that were completed below the UCCZ, multiple sources of information were reviewed, and the relevant information was analyzed in detail [40 CFR 146.84(c)(2)]. Table 3-16 presents a summary of the artificial penetrations of interest for developing the Corrective Action Plan. The following summarizes the findings to date for the Claimed as PBI legacy wells (excluding non-applicable water wells) identified in the AoR:

- Claimed as PBI

3.9.2 Corrective Action Plan for Artificial Penetrations

ExxonMobil developed a Corrective Action Plan for each artificial penetration that was identified to have the potential to act as a vertical conduit because it was not plugged, it was plugged and abandoned improperly, or not plugged in a manner that mitigates the movement of CO₂ or other fluids that could potentially endanger USDWs as required by 40 CFR 146.84(c) and (d).

For the well identified with plugging deficiencies, the basis for the corrective action strategy is to re-enter each well that has insufficient proof that it has been sealed to reduce the potential for vertical flow through the UCCZ and to install cement barriers inside the casing to mitigate migration potential through the casing. The CO₂-compatible cement material will be used where appropriate in accordance with 40 CFR 146.84(d).

3.9.2.1 Tabulation of Artificial Penetrations for Corrective Action

Figure 3-26 shows the location of the wells identified for corrective action in relation Claimed as PBI

Claimed as PBI as identified for corrective actions prior to injection based on the expected arrival times of the CO₂ plume and pressure front.

As described in the Testing and Monitoring Plan of this Application, direct and indirect monitoring technologies will be used to track the CO₂ plume and pressure front. A planned reevaluation of the AoR will occur after five years of injection and throughout the lifecycle of the Project. If at any time the rate of the CO₂ plume or pressure front expansion is predicted to

impact [REDACTED], the Corrective Action Plan will be amended to include the necessary corrective action to reduce the potential for USDW endangerment in accordance with 40 CFR 146.84(b)(2)(i)–(iv).

3.9.2.2 Analysis of Wells Identified for Corrective Action

Table 3-18 summarizes the available information concerning the borehole or well completion features and the P&A activities, as appropriate. ExxonMobil reviewed this information and determined the specific defects that require mitigation under 40 CFR 146.84(c) and (d).

Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

3.9.3 Corrective Action Sequence Plan

The following corrective action sequences will be undertaken in accordance with 40 CFR 146.84(c)(3) for the two artificial penetrations listed in Table 3-17. The planned actions are based on proposed plugging activities for the stratigraphic well or to plug deficiencies potentially present in the legacy well based on the available records (Table 3-18). Each artificial penetration in the CO₂ plume will be re-entered, and if sufficient barriers are not present, each well will have the appropriate barriers installed during the corrective action P&A field operations. The barriers will be established at the UCCZ, the surface casing shoe, the base of the lowermost USDW, and wellhead surface. The barrier at the UCCZ will be constructed of CO₂-compatible material consistent with 40 CFR 146.84(d).

A general approach for well re-entry and corrective actions is summarized in the sections below. A detailed summary of the corrective action sequence for each well is presented in Table 3-19 and as specific well schematics for each well to be re-entered in Appendix C.

[REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

[REDACTED]

Claimed as

[REDACTED]

PBI

[REDACTED]

[REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

Claimed as
PBI

[REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

A cement that is compatible with CO₂ will be used as the UCCZ cement plug. ExxonMobil will evaluate potential cement options prior to implementing the cementing operations with concurrence of the UIC Program Director. The intent is to select a cement system that is designed to provide a long-term cement sheath or plug that can withstand the temperature, pressure, and chemical interactions.

[REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

3.9.4 Site-Specific Review of Corrective Actions

Table 3-19 provides the corrective action sequences for the [REDACTED] Claimed as PBI provide the well schematics of each legacy well that will be re-entered for evaluation and re-plugging that have been developed based on the historical information and based on completion of the associated proposed corrective actions.

Claimed as PBI

Claimed as PBI

3.9.5 [redacted] Claimed as PBI

The following section outlines the plan for the P&A and conversion of the stratigraphic well referred to as [redacted] Claimed as PBI. The stratigraphic well was completed in the immediate vicinity of the injection wells for the purpose of gathering site-specific physical and chemical information on the confining and injection zones as well as to conduct conductivity testing. Once the data gathering activities have been completed, the stratigraphic well will [redacted]

Claimed as PBI

3.9.5.1 Pre-Plugging Activities (Notifications, Permits, and Inspections)

ExxonMobil will comply with reporting and notification provisions for stratigraphic wells drilled in Texas in accordance with RRC. The following notifications and permits will be submitted:

- [redacted] Claimed as PBI

ExxonMobil will also submit these records to the UIC Program Director for completeness purposes.

[redacted]

Claimed as PBI

[redacted]

[redacted]

Claimed as PBI

[redacted]

[redacted]

3.9.6 Plan for Site Access

In accordance with 40 CFR 146.84(b)(2)(iv) and 40 CFR 146.84(d), ExxonMobil is in the process of negotiating land access for each of the artificial penetrations identified for corrective action. Research to identify the well owners via regulatory databases has been completed. The process of securing necessary access rights will be complete in advance of the final submittals to the UIC Permit Director for the Application. The limited number of legacy wells requiring corrective action prior to commencing operations is a significant factor in mitigating the risk for the Project.

ExxonMobil has an extensive history of successfully negotiating access agreements with landowners in southeast Texas. Discussions are underway with the owner and operators of record to enter into an access agreement to perform corrective action. As shown in Table 3-20, an access agreement is in place for [REDACTED]

Claimed as PBI
[REDACTED] If appropriate and necessary, ExxonMobil will seek plugging orders from the RRC in accordance with Subchapter C of Chapter 89 of the Texas Natural Resource Code to obtain access for corrective actions.

If the AoR reevaluation conducted at the minimum schedule of once every five years identifies the potential for corrective action requirements at additional wells, ExxonMobil will promptly begin review of the additional wells in accordance with the process described this Corrective Action Plan. If site access issues are identified for wells identified for corrective action, ExxonMobil will notify the UIC Program Director.

**Claimed as
PBI**

3.10 AoR Reevaluation Plan and Schedule

3.10.1 Frequency of AoR Reevaluation

ExxonMobil adopts the minimum frequency of five years for the AoR and Corrective Action Plan reevaluation. Information gathered from implementation of the Section 5 – Testing and Monitoring Plan will be used to evaluate whether a more frequent review period is warranted based on the observed conditions of CO2 plume and pressure front migration.

If an alteration of the AoR reevaluation frequency of a minimum of every five years is recommended, the change in frequency will be aligned with the data evaluation and findings relative to the degree of protectiveness of USDW. ExxonMobil acknowledges that any amendments to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate. ExxonMobil also acknowledges the requirement in 40 CFR 146.84(b)(2)(i) of “The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review.”

3.10.2 Content of the AoR Reevaluation

The requirements for AoR reevaluation are specified in 40 CFR 146.84(e) and include the following considerations:

- Reevalue the AoR in the same manner specified in 40 CFR 146.84(c)(1);
- Identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);
- Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d); and
- Submit an amended AoR and Corrective Action Plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendment to the AoR and Corrective Action Plan is needed. Any amendments to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.

3.10.3 Conditions Warranting AoR Reevaluation

The monitoring and operational conditions that would warrant a reevaluation of the AoR prior to the next scheduled reevaluation [i.e., the minimum fixed frequency established in 40 CFR 146.84 (b)(2)(i)] are outlined below. These triggering events are based on a review of the hydrogeological site characteristics, the AoR and plume model results, and the pre-operational and operational plans for the Project. For each triggering event, Table 3-21 provides a summary of how the monitoring and operational data will be used to inform an AoR reevaluation and how corrective action will be conducted to reduce the potential for threats to USDW, if any arise. If an AoR reevaluation were to occur, corrective actions will be reevaluated.

Table 3-21 provides a list of the potential triggers for an AoR reevaluation consistent with the requirements of 40 CFR 146.84(b)(2)(ii).

Table 3-21: Triggers for AoR Reevaluation

No.	Events that may Trigger an Unscheduled AoR Reevaluation, with concurrence of the UIC Program Director	How Will Monitoring and Testing Data Inform the AoR Reevaluation?	How Corrective Action will be Conducted to Reduce the Potential for Threats to USDW
1	Compliance with minimum fixed frequency of at least once every five years [40 CFR 146.84(b)(2)(i)].	The AoR may need to be reevaluated more frequently than the minimum fixed frequency based on significant changes in operations or results from site monitoring that differ from model predictions. In these cases, the schedule for AoR reevaluation may be updated appropriately.	ExxonMobil will notify the UIC Permit Manager that a more frequent AoR reevaluation is warranted based on significantly changed conditions. This notification will form the basis of a permit modification and updates to the relevant portions of the Application.
2	Significant changes in operations that mandate AoR reevaluation under 40 CFR 146.84(c) as outlined below.	AoR reevaluation will be informed by both planned changes to operations and by testing and obtaining monitoring data that signal potential unexpected CO ₂ plume migration impacting the extent of the AoR. Examples may include installation of an additional injection well or identification of new offset well installation by third parties. Certain short-term operational changes, such as temporary well shut-ins, are not expected to warrant AoR reevaluation.	ExxonMobil will notify the UIC Program Director of the plan for significant changes in operations by pre-permitting engagement and the necessary modifications to the permit. The UIC Program Director may require an AoR reevaluation prior to approving such operational changes or changes may be allowed to occur prior to reevaluation of the AoR. The AoR reevaluation will be submitted to the UIC Program Director within an agreed-upon timeframe of instituting such changes, as described in the AoR and Corrective Action Plan.
2A	Plan to significantly change injectate composition mixture.	Re-run the reservoir plume model with a new composition mixture. If plume extents increase, reevaluate the AoR.	Within one month of composition change, notify the UIC Program Director of significant change and potential need to reevaluate AoR.
2B	New offset operations are established that could affect the injection intervals.	Re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	Within one month of commencement of new operations, notify the UIC Program Director of significant change and potential need to reevaluate AoR.
2C	Measured supercritical gas saturation that greatly deviates from the modeled gas saturation.	Re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.

No.	Events that may Trigger an Unscheduled AoR Reevaluation, with concurrence of the UIC Program Director	How Will Monitoring and Testing Data Inform the AoR Reevaluation?	How Corrective Action will be Conducted to Reduce the Potential for Threats to USDW
2D	An injection well exhibits a significant anomalous change in surface pressure for a sustained period of time.	Incorporate new pressure information and re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.
2E	An injection well exhibits a significant anomalous change in bottomhole temperature for a sustained period of time.	Incorporate new temperature information and re-run the reservoir plume model with new data. If plume increases in shape or extents, reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on model results.
2F	Casing or tubing leak detected by casing integrity logging.	Investigate possible tubing leak and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.
2G	Positive pressure loss in tubing annulus.	Investigate possible pressure loss and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.
3	Results from site monitoring that differ from model predictions [40 CFR 146.84(b)(2)(ii)] as outlined below.	An evaluation of monitoring data [required under 40 CFR 146.90] indicates that CO ₂ and/or pressure front migration is significantly different than that predicted by the current AoR delineation model and, therefore, warrants an AoR reevaluation. The following examples provide specific criteria for differences in monitoring data and model predictions that may trigger an AoR reevaluation [40 CFR 146.84(b)(2)(ii)].	Notification of significant difference to UIC Program Director within one month of confirmed findings.
3A	Seismic event greater than M3.0 within 5.6-mile radius of injection well.	Evaluate pressure and temperature data relative to operating limits and pressures in the in-zone monitoring well. Evaluate the need to enhance monitoring program to confirm extent of CO ₂ plume.	If evidence of mechanical integrity issues may cause an endangerment to USDW cease injection, notify the UIC Program Director within 24 hours of the determination and implement the emergency and remedial response plan

No.	Events that may Trigger an Unscheduled AoR Reevaluation, with concurrence of the UIC Program Director	How Will Monitoring and Testing Data Inform the AoR Reevaluation?	How Corrective Action will be Conducted to Reduce the Potential for Threats to USDW
			approved by the UIC Program Director. Operations will resume upon UIC Program Director concurrence that necessary remedial or corrective measures have been taken such that the risk to the USDW is as low as reasonably practicable.
3B	Annual plume migration survey identifies the plume migration direction that is significantly different then the modeled direction of migration.	Re-run the reservoir plume model incorporating injection well pressure and temperature data for calibration and other available information on plume migration and reevaluate the AoR.	Within one month of detection, ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on calibrated model results.
3C	The horizontal CO2 plume migration rate is significantly different than predicted.	Re-run the reservoir plume model incorporating injectors data for calibration and new information on plume migration and reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on calibrated model results.
3D	Sustained acoustic anomaly, which is unrelated to oil and gas activity in the area, detected by seismic survey or noise log.	Investigate seismic survey data anomaly and decide if the change triggers contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on seismic survey data analysis and or results from contingency monitoring.
3E	Statistically significant increases of indicator parameter concentrations above baseline for USDW samples of TDS, major cations and anions, CO2 concentration, isotopic values, or pH.	Resample fluid sample that contained the elevated concentrations and compare resample results with numerical criteria for trends and/or exceedances of target concentrations.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on resampling results and data evaluation.
3F	The presence of separate- phase CO2 in the sampled fluids above the confining zone, but below the lowermost USDW resulting from CO2/fluid migration out of the injection zone.	Investigate possible migration pathways and trigger contingency monitoring to reevaluate the AoR.	ExxonMobil will notify the UIC Program Director of results from the AoR reevaluation based on contingency monitoring results.

-Page Intentionally Left Blank-



Underground Injection Control – Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 4 – WELL CONSTRUCTION PLAN AND OPERATING CONDITIONS

Rose Carbon Capture and Storage Project
Jefferson County, Texas
ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2025

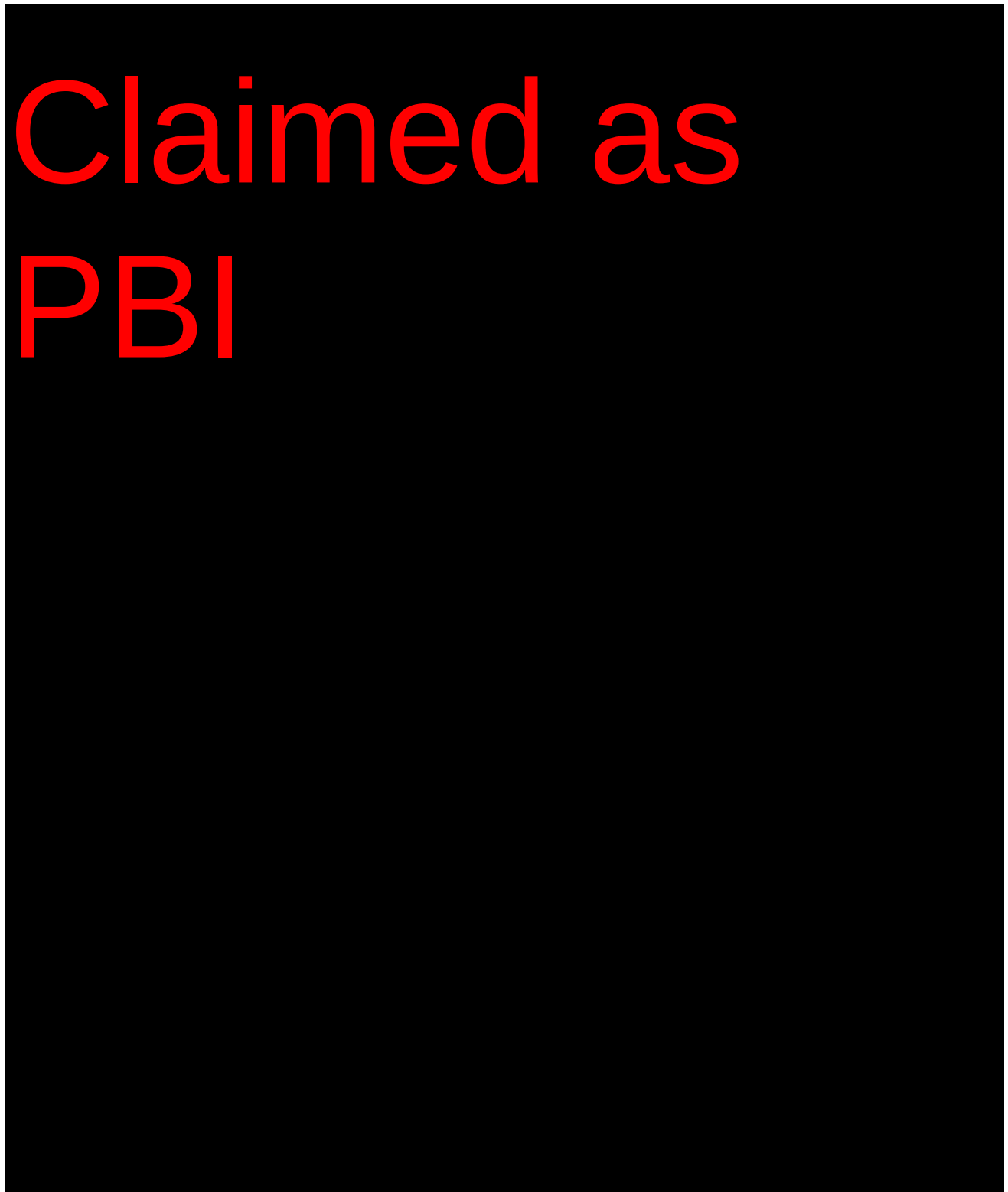
SECTION 4 – Well Construction Plan and Operating Conditions

TABLE OF CONTENTS

4.0	Well Construction Plan and Operating Conditions.....	5
4.1	Objectives.....	5
4.2	Engineering Design.....	6
4.2.1	Overview of Injection Well Perforation Strategy.....	7
4.2.2	Production Casing Design and Completion	9
4.2.3	Injection Tubing Design and Completion	12
4.2.4	Surface Conductor Pipe Design and Completion.....	15
4.2.5	Surface Casing Design and Completion	15
	Claimed as PBI	17
4.2.7	Safety and Continuous Monitoring Device Design and Completion	18
4.2.8	Wellhead Equipment Design and Completion	20
4.3	Well Drilling and Completion Design	23
	Claimed as PBI	26
4.3.4	Injection Well Completion Stage and Injection Interval	28
4.4	Pre-Operational Testing Plan.....	30
4.4.1	Tests During Well Drilling and Construction	31
4.4.2	Injection and Confining Zone Core Sampling	31
4.4.3	Injection Zone Characterization	32
4.4.4	Fracture Pressure, Fluid Characteristics, and Downhole Conditions	33
4.4.5	Injection and Confining Zone Formation Testing	33
4.4.6	Quality Assurance Surveillance Plan.....	34
4.5	Injection Well Operating Strategy.....	35
4.5.1	Injection Rate and Pressure	35
4.5.2	CO2 Volume	37
4.5.3	Annulus Pressure.....	38
4.5.4	Well Stimulation Procedures	38
4.5.5	CO2 Stream Characteristics.....	38
4.6	Operational Reporting Plan.....	38

4.7 Injection Well Construction and Operation Summary 39

List of Tables



Claimed as PBI

List of Figures

Claimed as PBI

Appendix D – Well Construction Schematics and Procedures

Claimed as
PBI

4.0 Well Construction Plan and Operating Conditions

On March 7, 2024, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) submitted a Class VI permit application to the U.S. Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage (CCS) Project (Project). ExxonMobil is undertaking the Project in Jefferson County, Texas, to sequester a [REDACTED]

[REDACTED] Claimed as PBI [REDACTED] The predicted total CO₂ storage is [REDACTED] Claimed as PBI [REDACTED]. The Well Construction Plan and Operating Conditions (Section 4) of the permit application contained information on the well construction and operating conditions in compliance with the requirements of the Code of Federal Regulations, Title 40, Sections 146.82 and 146.86 [40 CFR 146.82 and 146.86] and Texas Administrative Code, Part 1 Title 16 Chapter 5.

Following initial permit submission, additional well construction and operating condition data have become available through the stratigraphic well's ([REDACTED] Claimed as PBI [REDACTED]) data acquisition and analysis program. The purpose of this amendment is to incorporate the recently obtained data into the Well Construction Plan and Operating Condition section of the permit application to facilitate the evaluation of site suitability for sequestration of CO₂.

The three injection wells are designed for the sole purpose of injection and storage of CO₂ safely in the Upper Frio and Fleming Sand injection intervals at the Project site, and to contain the CO₂ within the injection intervals protecting underground sources of drinking water (USDWs). The formation properties of the injection intervals make the Project site an excellent candidate for injection of CO₂, with h [REDACTED]

[REDACTED] Claimed as PBI [REDACTED] Interbedded and overlying shale layers confine the injection intervals from USDW.

The well materials are compatible with all fluids with which they may come into contact and the design considered the depth of all porous formations, as identified during site characterization. The well design and materials are also appropriate for the proposed operating parameters. The planned formation testing at the injection well locations will be sufficient to fill potential gaps in available site characterization data and address key uncertainties in the Area of Review (AoR) delineation modeling.

The injection well construction specifications and testing plan are tailored to account for the data acquired from the logging, testing, and preliminary results from a stratigraphic well ([REDACTED] Claimed as PBI [REDACTED]) that was completed in close proximity to the three injection sites in 2023.

This section provides a narrative document with associated schematics and data summary tables that describe how ExxonMobil will construct the injection wells to meet the goals of 40 CFR 146.86. The engineering design is based on the collection of as much site-specific data as possible, particularly from the stratigraphic well, before submitting the initial Class VI Permit Application. This level of effort was undertaken to facilitate the permit modification process, between conducting the pre-construction activities required at 40 CFR 146.82(a) and the pre-operation phase activities required at 40 CFR 146.82(c).

4.1 Objectives

ExxonMobil developed the engineering design, pre-operational testing plan, and operating strategy for the injection wells to meet the following objectives:

CONFIDENTIAL BUSINESS INFORMATION

- The injection well construction design, material specifications, and construction will be compatible with the composition of the CO₂ stream over the duration of the Project to reduce the potential for endangerment of USDWs [40 CFR 146.82(a)(11),(12); 146.86].
- The injection wells will undergo logging and testing prior to operation to assess injection well and formation performance and update the operating strategy as necessary before injection of CO₂ [40 CFR 146.82(a)(8); 146.87].
- The injection well operating strategy provides continuous injection and annulus monitoring systems for each injection well to control injection pressure and trigger automatic shut-off devices and safety valves for CO₂ injection, consistent with safe operating procedures [40 CFR 146.82(a)(7),(9),(10); 146.88(e)].

4.2 Engineering Design

The engineering design parameters for the three injection wells are based on the planned injection rates, injection volumes, fluid properties, and chemical properties of the injectate fluid. In addition, the engineering design includes recompletion of each injection well to target specific injection intervals to achieve the target CO₂ storage amount.

ExxonMobil plans to inject a maximum volume of [REDACTED] for all three injection wells, which is an approximate rate of [REDACTED]. The tubing design, including size, weight, grade, and metallurgy is based on the properties of the injectate, rate of injection, and injection pressures determined by the detailed reservoir modeling.

The casing, cement, tubing, packer, continuous monitoring devices, and wellhead equipment were selected and designed to withstand the corrosive environment to which the materials and equipment will be exposed. Each was selected to have sufficient strength and material properties to withstand the pressure, temperature, and corrosive forces to which they will be subjected in the subsurface.

The following discussion presents the engineering design basis for the proposed well materials including casing, tubing, and cement. Well design schematics and locations are included in Appendix D.1-1 to D.1-9, which illustrate the well materials, design layout, and the locations of the packer and perforation intervals as well as the well location at the Project site.

The injection wells have been permitted for drilling through the RRC. A summary of the permitted well names and API numbers is as follows:

Injection Well Information:

Well Name and Number	[REDACTED] (Rose CCS Project Injection Well No. 01)

County	Jefferson

Location (RR D, S, A)	[REDACTED]

Latitude / Longitude (NAD83)	[REDACTED]

API	[REDACTED]

Claimed as PBI

Well Name and Number	[REDACTED] Rose CCS Project Injection Well No. 02)

Claimed as PBI

County

Jefferson

Location (RR D, S, A)

Latitude / Longitude (NAD83)

API

Claimed as PBI

Well Name and Number

Claimed as PBI (Rose CCS Project Injection Well No. 03)

County

Jefferson

Location (RR D, S, A)

Latitude / Longitude (NAD83)

API

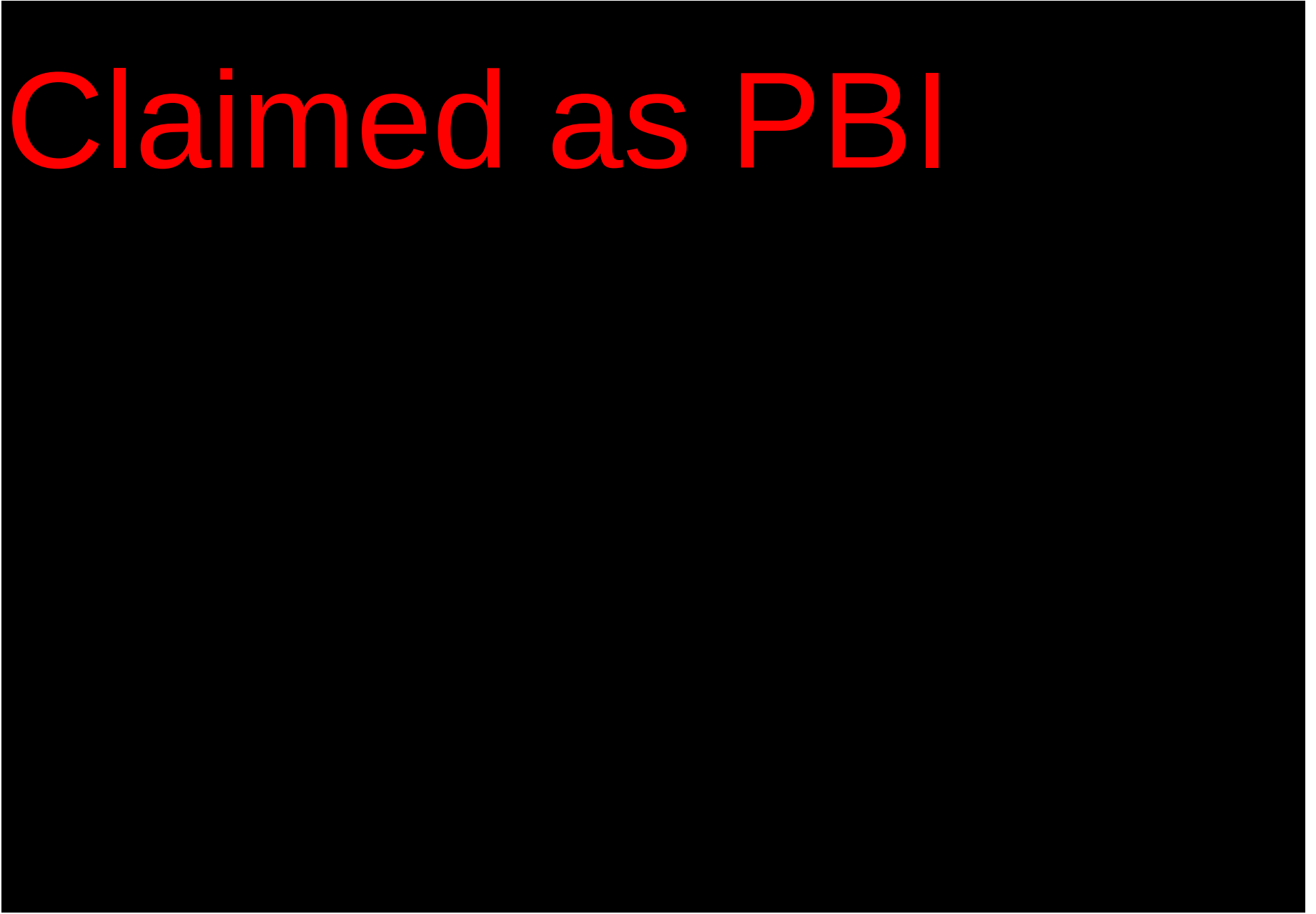
Claimed as PBI

The three injection wells are planned for drilling and completion beginning in Claimed as PBI ExxonMobil will utilize the strategy and procedures outlined in this plan and submit applicable and required permits and notifications to the RRC and EPA. The wells will be drilled and tested as described in the pre-operational testing plan described in Section 4.4.

4.2.1 Overview of Injection Well Perforation Strategy

Claimed as PBI

Claimed as PBI



4.2.2 Production Casing Design and Completion

[REDACTED]

Claimed as PBI

[REDACTED]

The well design allows for monitoring of each casing and tubing annulus for wellbore and mechanical integrity parameters. Appendices D.1-1 to D.1-9 provide the proposed wellbore designs and initial completion configurations for Injection Wells No. 01, No. 02, and No. 03, respectively, along with the certified well-location plats.

The production casing, or long-string casing, is the final, permanently cemented string of casing to be installed in each well. The production casing will be run from the surface to total depth (TD) and cemented back to the surface. The key design criteria for the long string includes the use of:

- [REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED]

To reduce the potential for CO₂ migration out of the injection interval, CO₂-compatible cement will be run from [REDACTED] Claimed as PBI, to provide a suitable barrier across the UCCZ. By using CO₂-compatible material, the cement is protected from carbonic acid, maintaining integrity throughout the life of the Project.

Throughout the life of each well, the Project will have [REDACTED]

Claimed as PBI

[REDACTED]

The engineering and design parameters for the production casing are summarized in Tables 4-4 and 4-5. These depths will be updated based on final logging of the injection wells.

Claimed as PBI

Claimed as PBI

Claimed as
PBI

Claimed as PBI

Claimed as
PBI

4.2.3 Injection Tubing Design and Completion

The [REDACTED] injection tubing size and material were selected for use in the Project wells based on injection volumes, rates, and injectate composition. Consistent with the design approach used for the casing strings, the injectate and the potential for a corrosive environment are important considerations when selecting the metallurgy of the tubing. The planned design offers protection

from the potential corrosive environment of the injectate stream and potential for influx of reservoir brine.

The production tubing will be [REDACTED] for its equivalent in all sections where the CO₂ will contact the tubulars. A tubing design analysis was conducted that considered calculated pipe-friction losses, exit velocities, and compression requirements.

Claimed as PBI

The input injection parameters from the model are shown in Table 4-11 and 4-12. The calculated injection parameters are shown in Tables 4-13 through Table 4-15 for Injection Wells No. 01 to No. 03, respectively.

Claimed as
PBI

Claimed as PBI

Claimed as
PBI

4.2.4 Surface Conductor Pipe Design and Completion

The unconsolidated nature of the sediments in the upper subsurface soil requires the installation of a conductor pipe to establish and maintain borehole integrity. A cellar will be installed, a

Claimed as PBI

4.2.5 Surface Casing Design and Completion

The surface hole will be drilled to below the USDW with a 17 1/2-in. bit, with surface casing set at approximately 2,200 ft for each of the injection wells. A string of 13 3/8-in. casing will be run and cemented with the casing centered in the open hole with centralizers. The generalized surface casing centralizer placement for the injection wells is provided in Table 4-18.

Claimed as PBI

A summary of surface casing design parameters is presented in Tables 4-19 through 4-21. The engineering calculations for the three injection wells are based on the wellbore conditions and maximum setting depth for the surface casing at Injection Well No. 02. Minor adjustments may be needed for actual surface casing installation at each of the injection wells based on site-specific conditions.

Claimed as PBI

Claimed as
PBI

Claimed as PBI

Claimed as
PBI

4.2.7 Safety and Continuous Monitoring Device Design and Completion

The following safety and continuous monitoring devices were designed for installation in the injection wells.

4.2.7.1 Safety Injection Valve

Claimed as PBI [REDACTED] In the event that injection is interrupted, the injection valve will limit the potential for fluid backflow into the injection tubing string and will keep the reservoir pressurized until equilibrium is achieved. When the safety injection valve is closed, it will maintain the injected CO₂ below the valve in a supercritical state.

Claimed as PBI

Claimed as
PBI

4.2.7.2 Downhole Pressure and Temperature Gauge Design and Completion

Claimed as PBI

. Figure 4-3 provides specifications of the downhole pressure and temperature gauge. This type of gauge or a suitable equivalent will be used depending on availability.

Claimed as PBI

4.2.7.3 Fiber Optic Design and Completion

Claimed as PBI

4.2.8 Wellhead Equipment Design and Completion

The wellhead is designed to manage working pressures and provide a high degree of mechanical integrity for the injection well.

Claimed as PBI

The wellheads will be configured as illustrated in Figure 4-4. Suitable equivalents for the specific manufacturers or equipment models indicated in the figure may be substituted as appropriate based on vendors used and equipment availability.

Claimed as PBI

-Page Intentionally Left Blank-

4.3 Well Drilling and Completion Design

4.3.1 Drilling and Completion Design for Injection Well No. 01

The proposed drilling and completion design for Injection Well No. 01 is described below.

Claimed as PBI provides the well design and completion details and the certified well plot map.

The final completion depths may be modified based on actual formation depths and/or conditions encountered during drilling.

Claimed as
PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

o

Claimed as
PBI

Claimed as PBI

4.3.4 Injection Well Completion Stage and Injection Interval

Claimed as PBI

Claimed as
PBI

Claimed as PBI

[REDACTED]

Claimed as PBI

[REDACTED]

Claimed as
PBI

Each discrete injection stage was selected to maximize the use of the pore space and collectively maximize the usage of the acreage position for CO₂ sequestration. A summary of the planned injection stages and duration by sand unit are listed in Tables 4-22 through 4-35. These stages are based on the current geologic model and will be updated after integration of the stratigraphic well results.

Claimed as PBI

4.4 Pre-Operational Testing Plan

The scope of the pre-operational testing plan included geophysical and core data collection in the stratigraphic well, fluid sampling at target intervals, and pressure testing to assess the injection intervals. Certain verification and logging data may be collected at the injection wells as needed for the site characterization, plume model, and AoR determination. The Testing and

Monitoring Plan (Section 5 – Testing and Monitoring Plan) provides the data collection activities for the pre-operational phase and the operational phase of the Project. A summary of that discussion is provided below for ease of review, with reference to the complete discussion in Section 5 for the pre-operational testing plan.

4.4.1 Tests During Well Drilling and Construction

A variety of geophysical well logs were collected during the construction of the stratigraphic well to verify and evaluate further the depth, thickness, porosity, permeability, lithology, and formation fluid salinity in the relevant geologic formations. Data collected from the stratigraphic well will also be used to appropriately construct the injection wells and provide data to verify the design for mechanical integrity purposes.

The drilling procedure in Appendix D.2 discusses the detailed coring procedures for the stratigraphic well (Claimed as PBI). The coring depths, formations, and footages for full core samples are provided in Table 4-25. The cores taken from the stratigraphic well are near the injection wells and represent the properties of the injection and confining zones near the injection wells. Data acquisition from the stratigraphic well includes sufficient and representative information on the injection and confining zones porosities, permeabilities, petrologies, and mineralogies.

Claimed as
PBI

4.4.2 Injection and Confining Zone Core Sampling

During the drilling and completion of the injection wells, a subset of the stratigraphic well's logging and coring data collection plan will be used to verify certain key parameters for injection

well performance and AoR modeling. At this time, the following geophysical logs are planned for each injection well. The open-hole logging plan is detailed in Table 4-26. The cased-hole logging plan is detailed in Table 4-27.

Claimed as
PBI

4.4.3 Injection Zone Characterization

The injection zone is being characterized in detail using the data acquired in the stratigraphic well (Claimed as PBI) and outlined in Appendix D.2. The location of the stratigraphic well relative to the injection wells is provided on Figure 5-3. ExxonMobil collected characterization

data for each injection interval of the injection wells including formation fluid temperature, pH, and specific conductivity; formation pressure, and static fluid level.

4.4.4 Fracture Pressure, Fluid Characteristics, and Downhole Conditions

ExxonMobil will characterize the formation fluids in the injection zone using samples collected from the stratigraphic well. ExxonMobil will use these data to evaluate the compatibility of the injectate with the formation fluids in the injection zone. These groundwater samples that were collected during the pre-operation phase of the Project will form the baseline data for comparison with water quality data representing the operating and post-operating phases of the Project. In general, the baseline data established include pressure, temperature, fluid, and physical characteristics present in the injection intervals and above the UCCZ from a single sample event at the stratigraphic well and a routine sampling frequency for the USDW monitoring wells.

The sampling and analysis plan for the water sample collected above the UCCZ at the stratigraphic well is specified in Table 4-28. The USDW monitoring wells will be drilled and monitored to provide a representative baseline of geochemical concentrations and pressure conditions in the AoR and surrounding area as described in Section 5 – Testing and Monitoring Plan. The analyses of geochemical and water quality parameters for the groundwater samples from the USDW monitoring wells are specified in Section 5. Similarly, groundwater characterization between the lowest most USDW and the top of the UCCZ will be tested and sampled inside the limits of the AoR to establish a representative baseline of geochemical and pressure conditions of the monitoring zone in the local Project area.

Claimed as PBI

The groundwater samples were analyzed in the field for certain physical parameters including temperature, pH, alkalinity, dissolved oxygen, and electrical conductivity. Laboratory-based analyses included total dissolved solids, concentrations of cations, anions, CO₂, and methane. Samples for cations and anions will be collected in appropriate acid-washed bottles to eliminate possible contamination.

4.4.5 Injection and Confining Zone Formation Testing

ExxonMobil collected pre-operational formation tests and data logging from the stratigraphic well to provide needed data on the geologic and hydrogeologic properties of subsurface formations. A step-rate test and a pressure fall-off test were performed at the stratigraphic well using a maximum injection rate above operating injection rate. The recorded steps were above and below the fracture calculated fracture pressure. Tables 4-29 and 4-30 provide the step-rate injection test and pressure fall-off test parameters.

Claimed as PBI

Pressure transient well testing (e.g., a pressure fall-off test) was completed in the stratigraphic well and will be conducted in each of the injection wells as a part of completion activities. These tests are intended to confirm reservoir and operational parameters used in the permitting process and provide needed data on the geologic and hydrogeologic properties of subsurface formations. The following injection well fall-off pressure test procedures are proposed:

- A non-hazardous test fluid will be used during the injection test.
- Injection Well Fall-Off Pressure Test:
 - The purpose of this test is to evaluate the injectivity index, skin, and permeability-thickness of the injection intervals.
 - For each injection zone, an injectivity test will be performed.
 - Shut-in well and record pressure fall-off with downhole gauges over sufficient time for proper analysis.

4.4.6 Quality Assurance Surveillance Plan

ExxonMobil developed Quality Assurance Surveillance Plan (QASP) in Appendix E in this application as a supplement to the testing and monitoring requirements of this section as well as Section 5 – Testing and Monitoring Plan and Section 7 – Post-Inject Site Care and Site Closure

Plan. The goal of the QASP is to provide reliable data to verify that the Project is operating as permitted without endangerment to USDWs. The QASP provides a verifiable set of standards and controls that include the technologies, methodologies, frequencies, sample quality assurance, and procedures to demonstrate the collection data activities will provide accurate and reliable information about the Project operations. The QASP is unique to the Project, informed by site-specific details, monitoring technologies selected, and will be updated as the Project evolves in concert with the Testing and Monitoring Plan.

4.5 Injection Well Operating Strategy

4.5.1 Injection Rate and Pressure

Table 4-31 provides the proposed operations for the injection wells including injection rate and pressure by well. The maximum injection rates for the injection intervals of each well ranges from Claimed as PBI. The average injection rate range is from Claimed as PBI. Both the maximum and average injection rates are predicted to result in reservoir pressure rises that are below 90% of the critical fracture pressure, shown in Table 4-31. Both the injection rates and pressures are within the operating window of the injection wells.

Claimed as PBI

Claimed as
PBI

The proposed continuous monitoring and recording devices will demonstrate internal mechanical integrity [40 CFR 146.88(e)] and that the well is equipped with shutoffs and safety devices that are linked to final operating limits specified in the permit for each injection well. The anticipated bottomhole injection pressures and interval-specific pressure constraints are shown in Tables 4-32 through 4-34. The injection depths are based on the current geologic model and will be updated after integration of the stratigraphic well results. The injection rate schedule presented in this Application is based on defined rate limitations without the modeled projections predicting sufficiently high reservoir pressures that result in maximum BHP constraining predicted well operations.

Claimed as PBI

Claimed as PBI

4.5.2 CO2 Volume

ExxonMobil plans to inject approximately Claimed as PBI of CO2 over the life of the Project. It is projected that the CO2 will be injected and will remain in a supercritical state through the life of the Project. The Fleming and Upper Frio sands have relatively high porosity and high permeability. These reservoir properties and the lateral extent of the injection zone are projected to allow the system to store significant volumes of CO2 with limited reservoir pressure rise and is projected to result in relatively rapid pressure fall-off upon shut-in. The CO2 volume was determined to meet the requirements of managing the threat of endangerment to USDW.

Claimed as PBI

ExxonMobil is not proposing a stimulation program for the proposed injection wells. In accordance with 40 CFR 146.91(d)(2), if a stimulation program is proposed, ExxonMobil will provide an advance notice of the proposed stimulation procedures to the underground injection control (UIC) Program Director in writing at least 30 days prior to implementation.

The CO₂ stream chemical composition is described in Table 4-11.

Claimed as PBI

Section 5 – Testing and Monitoring Plan provides a description of the analyses of the CO₂ stream for the Project, including tests for potential impurities that may be present and whether such impurities might alter the corrosivity of the injectate downhole. The information provided in Section 5 was based on the expected chemical and physical characteristics of the CO₂ stream and will be used to refine the well operating parameters while maintaining compliance with the Class VI permits.

A sample of the CO2 stream will be collected and analyzed for the suite of parameters listed in Table 5-3 prior to commencing injection and throughout injection operations at the proposed frequency. The details of the sampling process and frequency are described in Section 5 for approval by the UIC Program Director.

During the operational phase of the Project, ExxonMobil will report, within 24 hours, a confirmed endangerment to USDWs to the UIC Program Director pursuant to the requirement in 40 CFR 146.88(f)(3); 146.91(c); and 146.94(b)(3), including:

- Evidence that the CO₂ plume or pressure front may endanger a USDW or USDWs;
- The non-compliance situation as it relates to a permit condition;
- Apparent malfunction of the injection system;

CONFIDENTIAL BUSINESS INFORMATION

- Triggering of a shut-off system or a loss of mechanical integrity; or
- A release of CO₂ to the atmosphere or biosphere.

ExxonMobil will cease injection and take all steps reasonably necessary to determine whether there may have been a release of CO₂ to an unauthorized zone in the event that there is a loss of mechanical integrity.

4.7 Injection Wells Construction and Operation Summary

The geologic setting for this Project is ideally situated for carbon sequestration because of the geologic properties of the injection and confining zones and the compatibility of the reservoir fluids with CO₂. The Project brings together the proven engineering practices of ExxonMobil in the design of the wells with a state-of-the-art monitoring system and a robust reservoir management strategy. The proposed well designs are engineered to address the potential risks associated with the installation and operation of Class VI injection wells with a primary objective of protecting USDW from the threat of endangerment. The engineering design of the casing setting points, materials, and cement meet and exceed the requirements for Class VI injection well and for the conditions that have been projected for the Project. ExxonMobil will comply with the requirements and regulations required by the UIC Program Director for the well design and completion standards and the continuous monitoring and safety equipment to be installed. In addition, the operating strategy is designed to manage the pressure effects of CO₂ injection in the injection zones, to use the available pore space to the fullest extent, and to mitigate potential issues through a robust operational and testing and monitoring strategy.

-Page Intentionally Left Blank-

□

a						R		e
	a	e						

edera arbor Reere e adae

Claimed as PBI




Le monde est en train de changer. Les technologies évoluent à une vitesse fulgurante, et les attentes des consommateurs sont de plus en plus élevées. Pour rester compétitif, les entreprises doivent adopter une approche innovante et agile. C'est pourquoi nous avons décidé de lancer ce projet ambitieux. Nous sommes convaincus que cela nous permettra de répondre aux défis du futur et de créer une valeur durable pour nos clients et nos investisseurs. Ensemble, nous pouvons faire la différence.

- **De ce este important să cunoaștem și să înțelegem procesele de dezvoltare a sistemelor de operare?**
Cunoașterea proceselor de dezvoltare a sistemelor de operare este esențială pentru a înțelege cum funcționează sistemul de operare și pentru a putea rezolva problemele care apar în timpul utilizării acestuia.
- **De ce este important să cunoaștem și să înțelegem procesele de dezvoltare a sistemelor de operare?**
Cunoașterea proceselor de dezvoltare a sistemelor de operare este esențială pentru a înțelege cum funcționează sistemul de operare și pentru a putea rezolva problemele care apar în timpul utilizării acestuia.
- **De ce este important să cunoaștem și să înțelegem procesele de dezvoltare a sistemelor de operare?**
Cunoașterea proceselor de dezvoltare a sistemelor de operare este esențială pentru a înțelege cum funcționează sistemul de operare și pentru a putea rezolva problemele care apar în timpul utilizării acestuia.
- **De ce este important să cunoaștem și să înțelegem procesele de dezvoltare a sistemelor de operare?**
Cunoașterea proceselor de dezvoltare a sistemelor de operare este esențială pentru a înțelege cum funcționează sistemul de operare și pentru a putea rezolva problemele care apar în timpul utilizării acestuia.

□□□ □□r□□S r□□□□□d□□□r□□□□r□□s□□□□dM□□□□r□□□□□□

[illegible]

- Claimed as PBI

e e Tea ure e ey r a r a r r a r r e de a e
 e a r Claimed as PBI
 M b e ed a are y e a a d u ed e - rea Re e a d
 rre e a de y a d e a u e e e a r

Claimed as PBI

ter e ar a ad er re ere dee ed be a er r bab y a d
e ue e

[illegible]

- [REDACTED]
 [REDACTED] Claimed as PBI [REDACTED]

e d e a e r R e r e e e
 a d a e

[illegible]

M b u a e e e r r a D r e r a a d e e a r
 u d a e e e a d M r a r u e b a r e a d e e r
 e y e e e e e e a d r r a e y b e a a e d r
 e r e a e a u r e e u e a d r e u r r a a a d e r e
 r d e r e a b e d a a r r e e a u a e R d e

Claimed as PBI

Claimed as PBI

□□□□ □s□□□□□□s□d□□d□r□r□□□r□d□□□r□□□□

[illegible]

Claimed as PBI

Claimed as PBI

a d c a a a d e e d a r r a e r a e u e a d
b r e i r e t u r e r o d u r a e e r e n d F r a e R r e a u a r r e
b e u e d a a e e a d e u a y e e a d r r r a d e e e a
e a a e u d u r a d a e r e e d a r r a e e e e a r y d e r a e
r e D

Claimed as PBI

edea **aer** **Rae** **rre** **e**

ad **ae**

Claimed as PBI

- o The information contained in this document is the property of the company and is to be used only for the purpose for which it was provided. It is to be kept confidential and not disclosed to any third party without the prior written consent of the company.
- o The information contained in this document is the property of the company and is to be used only for the purpose for which it was provided. It is to be kept confidential and not disclosed to any third party without the prior written consent of the company.

The information contained in this document is the property of the company and is to be used only for the purpose for which it was provided. It is to be kept confidential and not disclosed to any third party without the prior written consent of the company.

5. Recovery Requirements

The information contained in this document is the property of the company and is to be used only for the purpose for which it was provided. It is to be kept confidential and not disclosed to any third party without the prior written consent of the company.

6. Records Management

The information contained in this document is the property of the company and is to be used only for the purpose for which it was provided. It is to be kept confidential and not disclosed to any third party without the prior written consent of the company.

The information contained in this document is the property of the company and is to be used only for the purpose for which it was provided. It is to be kept confidential and not disclosed to any third party without the prior written consent of the company.

The information contained in this document is the property of the company and is to be used only for the purpose for which it was provided. It is to be kept confidential and not disclosed to any third party without the prior written consent of the company.

Claimed as PBI

The first part of the text discusses the importance of the first part of the text. The second part of the text discusses the importance of the second part of the text. The third part of the text discusses the importance of the third part of the text. The fourth part of the text discusses the importance of the fourth part of the text. The fifth part of the text discusses the importance of the fifth part of the text. The sixth part of the text discusses the importance of the sixth part of the text. The seventh part of the text discusses the importance of the seventh part of the text. The eighth part of the text discusses the importance of the eighth part of the text. The ninth part of the text discusses the importance of the ninth part of the text. The tenth part of the text discusses the importance of the tenth part of the text.

Claimed as PBI

e d e e a e r R e r e e e
a d a e

[illegible]

e a u a r e u r e b e e e u b a d e e e a r b e e r e d a
 u u b a e r e u r e a u e e a u u b e e d e d a a a a e e
 y e r i a u a b e e u a e y e a d e a a r r e u r e r u e e u d e
 e e r a e e a u u a e e y e b e a a e d u u e
 u e r a a y a d a e e a a e d u e u u a d u e e e r a u r a d
 r e u r e r a a e a u u a a r e b e e u e d a e e r a d u c e r r i a
 a r r e d r e e a a d a d e e d e u d e e a y a u u u d a d d e d r
 r e e d b e r e r d e d a u u a e e e b e r e r d e d a y d a y e e
 u r

er FR re ure be a a ed e a u a a ue a ea
rea er a e e re ure M b e a u u a r r e ud
a r ed by e r ra Dre r y e be e u a a re ure e
a u u r r e ud r a d be ed e ar r a u ab e
e u a e y e de ed a re ure dr be e

Claimed as PBI

[illegible]

[REDACTED]

a e u r a e e b d
a d a m e b e d u e d e r a a u r e u e y e e r y
e y e a e e r e e a

Claimed as PBI

5

M

 r

 r

 u

Claimed as PBI

Claimed as

PBI

5 e e a u a a d a e

d u e e - e ru a a d e a e e b d
 be ru a e e a a bee ru a d e e e d a d u e e e e ur a
 a e a e e be d u e d a e e e u a y e e e b a e e
 e a b e a d e e e e a e e e r d u a a e r
 e e e d F e a a e e e e u e e u d e u b a d
 a e a e b y a a e e r a e e r u u b e r u e e e e e a
 e b a e e u r e y r e a u u r e r e a u r e y e b e e e a b e
 d e e b e e a a

Receivable accounts may be entered either manually or by computer. The computer may be used to enter the data from the sales invoice or from the sales order. The computer may also be used to enter the data from the sales order or from the sales invoice. The computer may also be used to enter the data from the sales order or from the sales invoice.

e a e e re rded e e r a e re e be a a y ed de y a d a e
 a r r adre FR d

□ □ □ □ □ r □ s s □ r □ □ □ □ □ □ □ □ □ □ □ s □ □ □ □ □ □

Required reference material to be included

Claimed as PBI

5 e Me d

Procedure du faire une affaire

- Records data recorded in the e-mail system may be used for a variety of purposes. Records may be used to determine the date and time of the e-mail, the sender and recipient, the subject, the content, and the attachments. Records may also be used to determine the date and time of the e-mail, the sender and recipient, the subject, the content, and the attachments. Records may also be used to determine the date and time of the e-mail, the sender and recipient, the subject, the content, and the attachments.
- Every e-mail system has a log of e-mails sent and received. The log is a record of the e-mail system's activity. The log is a record of the e-mail system's activity. The log is a record of the e-mail system's activity.
- For e-mail records to be a valid record, they must be a record of the e-mail system's activity. The log is a record of the e-mail system's activity. The log is a record of the e-mail system's activity. The log is a record of the e-mail system's activity.
- Each e-mail system has a log of e-mails sent and received. The log is a record of the e-mail system's activity. The log is a record of the e-mail system's activity. The log is a record of the e-mail system's activity.
- The e-mail system's log is a record of the e-mail system's activity. The log is a record of the e-mail system's activity. The log is a record of the e-mail system's activity.

5 May Monday

[illegible]

Ce re ure ta e re u be ub ed e Dr e r day
 e e ua ya ura e ua y r er a e re ure da a

Claimed as PBI

Claimed as PBI

Claimed as PBI

[illegible]

Claimed as PBI

□

□

□□a□e□□□□e□□□□a□y□□e□□Ba□□□

□

□a□e□□□□□□□□□□

by the end of the day, the first of the three
referred to the first of the three
the first of the three
the first of the three

5 u e a d r e f r a d r e e y a t e u e

Claimed as PBI

Claimed as PBI

Claimed as PBI

edeeaaerarraReerreee
adaae

**Claimed as
PBI**

 □ □ □ □ □ □ □ □ □ □ r □ □ □ □ □ □ □ □ s □ □ □ □ r □ □ d □ □ □ r M □ □ □ □ r □ □ D □ □ □ □

5 ordered members

[illegible]

Claimed as PBI

Claimed as PBI

Claimed as PBI

[illegible]

Claimed as PBI

Claimed as PBI

Claimed as

PBI

[REDACTED]

[REDACTED]
 [REDACTED]
 [REDACTED]
 [REDACTED]

	[REDACTED]	☐
	[REDACTED]	
	[REDACTED]	☐
	[REDACTED]	
	[REDACTED]	☐
	[REDACTED]	
	[REDACTED]	☐
	[REDACTED]	

Claimed as PBI

[illegible]

Claimed as PBI

arranged further they be added here as usual reference as ad de a day
eud a e d e a a n r y u e u a t e a e e e c a r

Claimed as PBI

Figure 6

The figure displays two rows of colored squares representing different categories. The top row contains 20 squares, and the bottom row contains 18 squares. The colors are as follows:

Row	Color	Count
Top Row	White	1
Top Row	Light Blue	1
Top Row	Dark Blue	1
Top Row	Green	1
Top Row	Yellow	1
Top Row	Pink	1
Top Row	Orange	1
Top Row	Red	1
Top Row	Brown	1
Top Row	Grey	1
Top Row	Black	1
Top Row	White	1
Top Row	Light Blue	1
Top Row	Dark Blue	1
Top Row	Green	1
Top Row	Yellow	1
Top Row	Pink	1
Top Row	Orange	1
Top Row	Red	1
Top Row	Brown	1
Top Row	Grey	1
Top Row	Black	1
Bottom Row	White	1
Bottom Row	Light Blue	1
Bottom Row	Dark Blue	1
Bottom Row	Green	1
Bottom Row	Yellow	1
Bottom Row	Pink	1
Bottom Row	Orange	1
Bottom Row	Red	1
Bottom Row	Brown	1
Bottom Row	Grey	1
Bottom Row	Black	1
Bottom Row	White	1
Bottom Row	Light Blue	1
Bottom Row	Dark Blue	1
Bottom Row	Green	1
Bottom Row	Yellow	1
Bottom Row	Pink	1
Bottom Row	Orange	1
Bottom Row	Red	1
Bottom Row	Brown	1
Bottom Row	Grey	1
Bottom Row	Black	1

[illegible]

- □ □ a □ e □ □ □ D □ □
- □ □ a □ e □ □ □ □ a □ ure □ □ □ a □ r □ a □ □ □ a □ d □ a □ □ □ □ □
- □ □ □ rea □ e □ □ □ □ □ □ □ □ e □ ra □ □ □ □ □
- □ De □ rea □ e □ □ □ □ □ □ □
- □ □ □ rea □ e □ □ □ □ □ □ □ □ e □ ra □ □ □ □ □ □ □ □ e □ a □ e □ □ □ ur □ e □ □ a □ d □ □
- □ □ □ rea □ e □ □ □ □ □ □ □ □ e □ ra □ □ □ □ □ □ □ □ ea □ ed □ □ □ □ □ □ □ ue □ □ □ □ □

e u d a e e b e r a r e d a a r e d e a d a e a r e d a b r a r y r
 a a y M b b e r e a d a r e d e a d a a r e r d a u
 r e r u e a r e d e r a e a d r a r a u d a y r b e
 e u e r e d

M b e r e a e a e a d a e b a r u a y a u r a e u a y
 r u r e e a e b e u e d a d a e e r e u e e d e d

[illegible]

e u d a e ere e ed r e ra r a e e a d ere a ay ed r a er
 ua ya d e e a ara e er e re u e e e ere r ded e -
 e . ara . er a e d B [REDACTED]

e d e e a e r a r R e r e e e e
 a d a e

M b u b a r e r u b a a d a b e a d e R R
 a d r e a r e r d a r d a e F R r a y e r d a e r e e u r e
 d d a y e e d u d d a a u d a u r e a d a a b e r e a e d r r e
 y e r d e e e u r e M r r d a a b e r e a e d r r a u y e r
 e e e u r e r d a a d e e e u r e r e r b e
 r e a e d r r y e r a e r e e u r e

 s **R** **d** **d** **s**

a r d a e FR e e a d M a b e r e e d a d
 re d a a u e ery e year

- de myrre e una araba ayarra ree a
- rra e r ad ae ee ary rra rea e r
e da er e D a d r
- De a r er ed d are ure a d a

Mobile rate increased in data area over the
 a road area needed a year to read a D and era
 a compliance with the UIC Director's re-e a a e d e be ub ed

Claimed as PBI

Claimed as PBI



Underground Injection Control – Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 6 – INJECTION WELL PLUGGING PLAN

Rose Carbon Capture and Storage Project
Jefferson County, Texas
ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2025

SECTION 6 – INJECTION WELL PLUGGING PLAN

TABLE OF CONTENTS

6.0	Injection Well Plugging Plan.....	5
6.1	Objectives	5
6.2	Preparation of Well Prior to Plugging	6
6.2.1	Flushing Well with Kill Weight Fluid.....	6
6.2.2	Removal of Well Components and Obstructions	6
6.2.3	Planned Tests or Measures to Determine Bottomhole Pressure	6
6.2.4	Planned External MITs.....	7
6.2.5	CO2-Compatible Materials	7
6.2.6	Planned Site Restoration Activities	8
6.3	Injection Well Zonal Isolation and Final P&A	8
6.3.1	Zonal Isolation and Intermediate Plug-Back Plan.....	8
6.3.2	Final P&A.....	9
6.4	Notifications and Record Keeping	14
6.5	Monitoring Well P&A	15
6.6	Amendments to the P&A Plan	15

List of Tables

Table 6-1: External MIT Methods	7
Table 6-2: Common Cement Additives.....	7

Claimed as PBI

Appendix H – Plugging Schematics and Procedures

[REDACTED]

Claimed as PBI

[REDACTED]

-Page Intentionally Left Blank-

6.0 Injection Well Plugging Plan

On March 7, 2024, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) submitted an Underground Injection Control Class VI permit application to the United States Environmental Protection Agency for the Rose Carbon Capture and Storage (CCS) Project (Project). ExxonMobil is undertaking the Project in Jefferson County, Texas, to sequester a

[REDACTED] The predicted total CO2 storage is [REDACTED]

[REDACTED] The Injection Well Plugging Plan section for the Project Class VI Underground Injection Control (UIC) Permit Application was prepared to meet the requirements of the Code of Federal Regulations, Title 40, Section 146.92 [40 CFR 146.92] and Texas Administrative Code, Part 1 Title 16 Chapter 5 for plugging and abandonment (P&A) of the Rose CCS Project Injection Wells No. 01, No. 02, and No. 03. The purpose of the Plugging Plan is to demonstrate the actions that ExxonMobil will take to mitigate the threat to underground sources of drinking water (USDW) during the post-injection period.

Since the submittal of the Class VI permit application, ExxonMobil obtained a substantial amount of new data and analyses from the core sampling and analysis program for the Project's stratigraphic well ([REDACTED]). The major changes to the permit application are based on incorporating the recently obtained data into the Area of Review model and updates to the extent of the CO2 plume and critical-pressure front and the operating strategy for CO2 storage. In turn, these changes required updates to the Injection Well Plugging Plan to align with the stratigraphic well completed plugging procedures and updated subsurface data.

ExxonMobil has selected materials for plugging the injection wells that will resist the corrosive properties of the injection fluid to maintain mechanical integrity of the plug and well casing. The planned plugging procedures are aligned with best practices for restoring the upper composite confining zone (UCCZ) integrity at each injection well location. [REDACTED]

[REDACTED]

Separately, the procedures and details for the stratigraphic well P&A are included in this plan for completeness purposes.

6.1 Objectives

The Plugging Plan represents one of the final steps in the lifecycle of each of the three injection wells for the Project. ExxonMobil will properly plug and abandon the injection wells, maintain the integrity of the UCCZ throughout the remainder of the post-closure care period, and monitor the performance of the plugged wells to contain CO2 and brine in the injection zone, reducing the potential risk of USDW endangerment.

The Plugging Plan and procedures were designed to meet the following objectives:

- Measure the bottomhole reservoir pressure prior to conducting plugging activities [40 CFR 146.92(b)(1)];

CONFIDENTIAL BUSINESS INFORMATION

- Assess the external mechanical integrity of the long-string casing by using appropriate testing methods to demonstrate isolation consistent with 40 CFR 146.92(b)(2);
- Select the type, grade, and quantity of material to be used in plugging to withstand contact with CO₂ and acidified liquids in the injection intervals [40 CFR 146.92(b)(5)]; and
- Detail the methods, locations, and types of plugs used within the well [40 CFR 146.92(b)(4) and 40 CFR 146.92(b)(6)].

6.2 Preparation of Well Prior to Plugging

Prior to plugging, the well will be flushed with a kill weight fluid, the bottomhole pressure will be measured, well components will be removed as needed, and an external mechanical integrity test (MIT) will be performed. The proposed plugging methods and materials used are corrosion compatible to the injection interval conditions.

As needed, ExxonMobil will repair deficiencies identified during the life of the well to mitigate potential leaks to USDWs [40 CFR 146.88(f)]. Historical MIT data and prior remedial measures will be considered prior to plugging operations. If required, those remedial activities will be included in an amendment to this plan.

6.2.1 Flushing Well with Kill Weight Fluid

Pressure control will be accomplished through the use of kill weight brine that is weighted and compatible with the injectate and formation fluids. The kill weight brine fluids will be circulated through the injection well to remove fluids or fine debris that could have a significant impact on the integrity of cementing operations. The following components that have been in contact with injection or annular fluids will be flushed:

- Any components in the annular space between the injection tubing and the production casing;
- The long-string casing;
- The perforated injection zone; and
- The injection packer, if needed.

Claimed as PBI

After the well has ceased operation, flushing fluid will be circulated through tubing to flush the well of free solids, as necessary.

6.2.2 Removal of Well Components and Obstructions

The removal of well equipment prior to plugging will be completed to open the well for access. In general, uncemented and non-permanent components of the well will be removed. This includes downhole monitoring devices and potentially shut-off devices. The tubing will be pulled from the well.

The surface and long-string casings will be cemented to the surface and will remain in place.

6.2.3 Planned Tests or Measures to Determine Bottomhole Pressure

Claimed as PBI

Claimed as PBI

The bottomhole reservoir pressure will be used to estimate the density of kill weight brine needed to establish static equilibrium prior to plug placement.

6.2.4 Planned External MITs

MIT will be used to identify the potential for significant fluid movement toward the USDW in the casing, tubing, or packer [40 CFR 146.89(a)]. ExxonMobil will conduct at least one of the tests listed in Table 6-1 as part of the monitoring program, to verify external mechanical integrity as required in 40 CFR 146.92(a).

Table 6-1: External MIT Methods

Test Description	Method of Testing
Temperature Log	Claimed as PBI
Oxygen Activation Log	Wireline log
Radioactive Tracer Log	Wireline log

The results of the MIT will be documented and provided to the UIC Program Director.

6.2.5 CO₂-Compatible Materials

In accordance with 40 CFR 146.92(b)(3) and (5), a cement that is compatible with CO₂ will be used as the UCCZ cement plug. The procedures for corrective action on artificial penetrations of the UCCZ were described in Section 3 – Area of Review and Corrective Action Plan. ExxonMobil will evaluate potential cement options prior to implementing the cementing operations with concurrence of the UIC Program Director. The intent is to select a cement system that is designed to provide a long-term cement sheath or plug that can withstand the temperature, pressure, and chemical interactions.

Cement at intervals above the UCCZ will be based on blended Portland cement. A list of common cement additives is provided in Table 6-2 for the blended Portland cement to improve setting time, reduce porosity, and improve overall strength if needed. ExxonMobil will report the wet density and will retain duplicate samples of the cement used for each plug in the plugging reports.

Table 6-2: Common Cement Additives

Additive Type/Category	Additives
Fluid-loss additive	Claimed as PBI
Dispersant	Claimed as PBI

CONFIDENTIAL BUSINESS INFORMATION

Additive Type/Category	Additives
	• [REDACTED] Claimed as PBI
Retarder	• [REDACTED] Claimed as PBI
Accelerator	• [REDACTED] Claimed as PBI
Antifoam agent	• [REDACTED] Claimed as PBI

[REDACTED]
Claimed as PBI

6.2.6 Planned Site Restoration Activities

After the injection wells have been plugged and abandoned, the wellhead equipment and surface facilities will be removed from the well site. The surface will be restored to a condition agreed upon by the landowner and by the UIC Program Director, as appropriate.

6.3 Injection Well Zonal Isolation and Final P&A

As discussed above, a plug will be set for injection zone isolation and the final P&A will occur at the end of the Project. The following details outline the procedures for both types of plugs to be installed. The volume and depth of the plugs will depend on the final geology and downhole conditions of the well as assessed during construction.

6.3.1 Zonal Isolation and Intermediate Plug-Back Plan

[REDACTED]
Claimed as PBI

6.3.1.1 Pre-Zonal Isolation Activities

ExxonMobil will comply with reporting and notification provisions for the UIC Program Director, which require a 60-day advanced written notice before planned recompletion efforts are undertaken [40 CFR 146.92(c)]. A similar notice of recompletion will be communicated to the Railroad Commission of Texas (RRC). The bottomhole reservoir pressure will be measured

using the [redacted] [40 CFR 146.92(a)]. Schematics of the initial completion plans for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03 are presented in Appendix D.1.

6.3.1.2 Zonal Isolation Activities

A barrier will be set above the injection zone to be isolated. This is generally completed via a bridge plug or a permanent packer with plug in nipple profile completed with approximately 10 ft of cement. The plug integrity will be assessed by conducting a pressure test or tagging. The perforations will not be squeezed.

6.3.2 Final P&A

After injection operations cease and after post-operational monitoring in a well is completed, the injection well will be prepared for final P&A. The general final P&A procedures are described below.

6.3.2.1 Pre-Plugging Activities (Notifications, Permits, and Inspections)

ExxonMobil will comply with reporting and notification provisions and provide written notification to the UIC Program Director 60 days before planned plugging efforts. If changes have been made to the original approved Injection Well Plugging Plan, ExxonMobil will provide the amended Injection Well Plugging Plan [40 CFR 146.92(c)]. A Notice of Intention to Plug and Abandon Form W-3A will be submitted to the RRC at least 5 days before plugging operations are planned to commence. In accordance with 40 CFR 146.92(d), a plugging report will be submitted to the UIC Program Director and RRC within 60 days after plugging. Plugging Record Form W-3 will be filed with RRC District Office 3 within 30 days after plugging.

The following plugging activities are planned for each injection well:

- The bottomhole reservoir pressure will be measured using the [redacted] [40 CFR 146.92(a)];
- The external mechanical integrity will be demonstrated through approved testing methods discussed above [40 CFR 146.92(a)]; and
- The injection well will be flushed with a kill weight fluid prior to pulling the injection tubing and packer [40 CFR 146.92(a)], as described in Table 6-3.

Claimed as PBI

6.3.2.2 Plugging Procedure, Injection Well No. 01

The following sequence of plugging procedures are planned:

1. [redacted] Claimed as PBI

PBI

Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03
Page 10 of 16

[REDACTED]

Claimed as

[REDACTED]

PBI

[REDACTED]

6.3.2.5 Plug Details, Injection Well No. 02

Table 6-5 provides the plugging details for Injection Well No. 02; Appendix H shows the final plugged schematic.

Claimed as PBI

The following sequence of plugging procedures are planned:

- Claimed as

Table 6-6 provides the plugging details for Injection Well No. 03; Appendix H shows the final plugged schematic.

Claimed as PBI

The procedures described above are subject to modification during execution, as necessary, for implementation of plugging operations that protect worker safety and the USDW. Significant modifications due to unforeseen circumstances will be reported to the UIC Program Director within 24 hours of occurrence during field operations and documented in the plugging report. Completed plugging forms, records, and lab information will be supplied to the regulatory agencies as required by the permit. The plugging report will be certified as accurate by ExxonMobil and the plugging contractor and will be submitted to the UIC Program Director within 60 days after plugging is completed [40 CFR 146.92(d)]. Well plugging reports, post-injection site care data (including data and information used to develop the demonstration of the

alternative post-injection site care timeframe), and the site closure report collected pursuant to the requirements in 40 CFR 146.93 (f) and (h), will be retained by ExxonMobil. Site closure and reporting is discussed in Section 7 – Post-Injection Site Care and Site Closure Plan.

The plugging report will provide the following information:

- Results of tests to determine BHP and mechanical integrity;
- Type and number of plugs used;
- Cement type, grade, weight, and quantity of material for plugs;
- Method of cement plug emplacement; and
- Top and bottom of each cement plug.

6.5 Monitoring Wells P&A

Monitoring wells must be plugged in accordance with 40 CFR 146.93(e) to not allow movement of injection or formation fluids that could endanger USDWs. Specific monitoring wells will remain in place after injection wells have been plugged and abandoned for use in monitoring activities associated with the Post Injection Site Care and Site Closure Plan. ExxonMobil will assess the monitoring well plugging procedures prior to P&A in relation to this plan. Documentation of appropriate P&A of the monitoring wells will be submitted to the UIC Program Director in accordance with 40 CFR 146.93(f)(1).

6.6 Amendments to the P&A Plan

The Plugging Plan will be amended to account for changes in conditions that trigger modification to the Area of Review. ExxonMobil will inquire with the UIC Program Director to confirm whether such changes in condition warrant amendments to the Plugging Plan. Revisions to the Injection Well Plugging Plan can be made at any time and submitted when notifying the UIC Program Director of the intent to plug the well at least 60 days prior to conducting the plugging activity [40 CFR 146.92(c)].

-Page Intentionally Left Blank-



Underground Injection Control – Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

Rose Carbon Capture and Storage Project
Jefferson County, Texas
ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2025

SECTION 7 – POST-INJECTION SITE CARE AND SITE CLOSURE PLAN

TABLE OF CONTENTS

7.0	Post-Injection Site Care and Site Closure Plan.....	5
7.1	Objectives.....	5
7.2	Calculation of Pre- and Post-Injection Pressure Differentials	6
7.3	Predicted Position of the CO ₂ Plume and Pressure Front at Site Closure.....	10
7.4	Post-Injection Monitoring Plan	13
7.4.1	PISC and Site Closure Plan Reviews and Amendments	13
7.4.2	Monitoring Above the UCCZ and USDW	14
7.4.3	In-Zone CO ₂ Plume and Pressure Front Tracking.....	15
7.4.4	Submitting PISC Monitoring Results.....	17
7.5	Demonstration of Non-Endangerment of USDW	17
7.5.1	Introduction and Overview for Non-Endangerment Demonstration	18
7.5.2	Summary of Existing Monitoring Data	18
7.5.3	Summary of Computational Modeling History.....	18
7.5.4	Evaluation of Reservoir Pressure	19
7.5.5	Evaluation of the CO ₂ Plume	19
7.5.6	Evaluation of Emergencies or Other Events	19
7.6	Site Closure Plan	19
7.6.1	Pre-Closure.....	20
7.6.2	Plugging Activities	20
7.6.3	Site Restoration.....	20
7.6.4	Documentation of Site Closure.....	20

List of Tables

Claimed as PBI

List of Figures

Claimed as PBI

-Page Intentionally Left Blank-

7.0 Post-Injection Site Care and Site Closure Plan

On March 7, 2024, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) submitted an Underground Injection Control Class VI Permit Application (Application) to the U.S. Environmental Protection Agency (EPA) for the Rose Cabon Capture and Storage Project (Project). ExxonMobil is undertaking the Project in Jefferson County, Texas to sequester a maximum of [REDACTED]

[REDACTED] The predicted total CO₂ storage is [REDACTED]
[REDACTED] A Post-Injection Site Care (PISC) and Site Closure Plan was submitted in Application in compliance with the requirements of the Code of Federal Regulations, Title 40, Section 146.93 [40 CFR 146.93] and Texas Administrative Code, Part 1, Title 16, Chapter 5. A revision to the PISC was prepared for the Amendment to address changes in the Area of Review (AoR) delineation model for the post-injection period of the Project.

Since the submittal of the Application, ExxonMobil obtained a substantial amount of new data and analyses from the data acquisition program for the Project's stratigraphic well [REDACTED]
[REDACTED]. The major changes to the Application are based on incorporating the recently obtained data into the AoR delineation model and new model results. [REDACTED]

[REDACTED] The new results required changes to the PISC that primarily focused on updates to the Section 5 – Testing and Monitoring Plan as well as calculations and modeling of the pressure front and CO₂ plume stabilization post-injection.

The PISC Plan describes the activities that will occur once injection operations have ceased, and the Project moves into maintaining a non-endangerment condition for underground sources of drinking water (USDW). The Site Closure Plan will be implemented once ExxonMobil demonstrates to the Underground Injection Control (UIC) Program Manager that no additional monitoring is required to demonstrate protection of USDW and that the testing and monitoring system can be dismantled. ExxonMobil's strategy for PISC monitoring is based on the same systems and processes as described in Section 5 – Testing and Monitoring Plan of the Application. The major monitoring elements include continued measurements of the CO₂ plume and pressure front location, monitoring above upper composite confining zone (UCCZ) groundwater as well as USDW. The data collected from this activity will be used to confirm compliance with the water quality objectives for the Project and generate information needed to support the final non-endangerment demonstration and subsequent site closure. The end of the Project comes when the closure activities have been documented and approved by the UIC Program Director.

7.1 Objectives

The PISC and Site Closure Plan have been developed to meet the following objectives as outlined in 40 CFR 146.93:

- Describe the pressure differential between pre-injection and predicted post-injection pressures in the injection zones as well as the predicted positions of the CO₂ plume and associated pressure front at site closure;
- Describe the post-injection monitoring locations, methods, and proposed frequencies to demonstrate non-endangerment to USDW over the timeframe of the PISC;

CONFIDENTIAL BUSINESS INFORMATION

- Identify the pre-closure, plugging, and site-restoration steps to achieve approval for site closure; and
- Outline the documentation and recordkeeping practices that will provide the information for decision-making purposes.

ExxonMobil will not cease post-injection monitoring until the non-endangerment demonstration pursuant to 40 CFR 146.93(b)(3) has been approved by the UIC Program Director. Pursuant to 40 CFR 146.93(b)(1), the default PISC monitoring timeframe is 50 years after cessation of injection. ExxonMobil will monitor groundwater quality and track the position of the CO₂ plume and pressure front for 50 years after cessation of injection unless a lesser period of time is approved by the UIC Program Director. Once the non-endangerment demonstration has been approved, ExxonMobil will plug the monitoring wells, restore each well pad to the landowner's agreed-upon condition, and submit a Site Closure Report to the UIC Program Director.

7.2 Calculation of Pre- and Post-Injection Pressure Differentials

As described in 40 CFR 146.93(a)(2)(i), the Class VI non-endangerment demonstration will establish that pressure has declined to a level that no longer poses potential endangerment of USDW. For the purposes of this section, ExxonMobil evaluated the pressure differentials by comparing the pre-operating pressure with the post-injection pressure differentials predicted by the plume model. The predicted pressure differential between pre-injection and the modeled post-injection pressures are favorable, showing a steep and continuous decline in pressure toward pre-operational baseline conditions. The primary mechanisms responsible for the anticipated pressure decay rates are the injection sequencing plan, the geological conditions of the injection zones (e.g., net sand thickness, permeability, porosity) and confining zones, and the projected CO₂ storage volume for the Project site.

A staged injection sequence is planned for the injection wells to optimize the storage of CO₂ in the three F

Claimed as PBI Section 3 – Area of Review and Corrective Action Plan and Section 4 – Well Construction Plan and Operating Conditions of the application provide detailed discussions of the injection sequencing strategy. Figure 7-1 summarizes the injection sequence schedule for the proposed **Claimed as PBI** injection period. The actual injection period will depend on the issuance of the permits for each injection well.

Claimed as PBI

Table 7-1 provides the model-predicted maximum pressure differential and the change in injection pressures in each injection interval over time pursuant to 40 CFR 146.93(a)(2)(i). Figure 7-2 presents a graphical representation of the pressure differential data provided in Table 7-1.

Claimed as PBI

Claimed as PBI

7.3 Predicted Position of the CO2 Plume and Pressure Front at Site Closure

Pursuant to 40 CFR 146.93(a)(2)(ii), the AoR was delineated using computational modeling that accounts for all phases of CO2 (e.g., supercritical, dissolved, etc.) under proposed operational conditions. The AoR consists of both the CO2 plume and the extent of the pressure front. The following discussion provides the predicted evolution of both the CO2 plume and pressure front throughout the course of the 50-year PISC timeframe.

Figure 7-3 shows the extent of the AoR and its subcomponents at [REDACTED]

[REDACTED]
[REDACTED]
Claimed as PBI
[REDACTED]
[REDACTED]

The CO2 plume from the three injection wells is indicated by the [REDACTED] **Claimed as PBI**, based on the maximum extent of any injection interval. [REDACTED]

[REDACTED]
Claimed as PBI
[REDACTED]
[REDACTED]

Claimed as PBI

CONFIDENTIAL BUSINESS INFORMATION

-Page Intentionally Left Blank-

7.4 Post-Injection Monitoring Plan

PISC monitoring is required by 40 CFR 146.93(b) to demonstrate that USDW is not endangered during the post-injection phase of the Project. Much like the operational phase, direct and indirect forms of monitoring will be used to track the evolution of the CO₂ plume and pressure front after cessation of CO₂ injection. The strategy for the Post-Injection Monitoring Plan is to rely on a core set of monitoring locations that were established during the operational phase of the Project. The following set of core monitoring locations were assumed to be installed and monitored pursuant to the Testing and Monitoring Plan and found sufficient pursuant to the AoR reevaluation process:

Claimed as PBI

Figure 5-4 in Section 5 – Testing and Monitoring Plan illustrates the locations of these USDW monitoring wells. In the event that additional monitoring locations are added during the course of the injection operations under the direction of the UIC Program Manager, this core set of monitoring wells will be updated to reflect the detection monitoring system found sufficient for CO₂ plume and pressure front migration evaluation at the close of the injection phase of the Project.

In accordance with 40 CFR 146.93(b)(1), monitoring of the pressure front and CO₂ plume will occur for at least 50 years or an alternate duration approved by the UIC Program Director. ExxonMobil is proposing a schedule to submit PISC monitoring results annually and within 30 days of the anniversary date of injection cessation [40 CFR 146.93(a)(2)(iv)].

The following discussion provides details on the elements of the PISC monitoring strategy outlined above.

7.4.1 PISC and Site Closure Plan Reviews and Amendments

As required by 40 CFR 146.93(a)(3), ExxonMobil will submit an amended PISC and Site Closure Plan or demonstrate that no amendment is needed upon cessation of injection. Amendments to the plan, or the demonstration that no revisions are necessary, will be based on monitoring data collected during injection and the most-recent AoR delineation. The plume model will continue to be updated throughout the Project using monitoring information and the AoR reevaluation process and reporting requirements.

During PISC monitoring, ExxonMobil will conduct periodic reviews to incorporate new monitoring data, changes to the site computational model that may warrant changes in PISC monitoring, and/or changes in the methodology proposed to demonstrate non-endangerment of USDW. This approach will also support the use of new technologies that may be available in the future that facilitate a higher level of performance than the existing system. Pursuant to 40 CFR 146.84(e) and as described in Section 4 – Well Construction Plan and Operating Conditions, ExxonMobil will reevaluate the AoR periodically by comparing model predictions with monitoring results. Following an AoR reevaluation process, if the AoR and Corrective Action Plan are

amended, ExxonMobil will review the PISC and Site Closure Plan to determine whether any updates are needed to ensure consistency across all plans. ExxonMobil may submit an amended PISC that describes how changes to the model affect predictions of pressure dissipation, plume migration rates, CO₂ trapping, and additional processes that need to be accounted for in the non-endangerment demonstration.

In accordance with 40 CFR 146.93(a)(4), at any time during the life of the Project, ExxonMobil may modify and resubmit the PISC and Site Closure Plan for the UIC Program Director's approval within 30 days of such change.

7.4.2 Monitoring Above the UCCZ and USDW

During the injection phase, periodic monitoring of groundwater quality for significant geochemical changes above the UCCZ is required by 40 CFR 146.90(d) for the purpose of detecting potential leakage through the UCCZ. As described in Section 2 – Site Characterization, the UCCZ is a [REDACTED]

Claimed as PBI [REDACTED]. In accordance with 40 CFR 146.93(b)(1), groundwater quality and geochemical characteristics will be monitored in the AZMI at Claimed as PBI [REDACTED] and in the USDW at USDW Monitoring Wells No. 01, No. 02, and No. 03 during the post-injection period.

ExxonMobil's strategy for monitoring groundwater above the UCCZ is a risk-based approach correlated to modeled CO₂ plume and injection zone characteristics. By the time the PISC monitoring program is initiated, the risk mitigating effects of injection sequence plan, the operating strategy, and corrective actions taken on artificial penetrations will likely have demonstrated protection of USDW throughout the operational phase of the Project. The list of analyses to be performed at these monitoring wells is summarized in Table 7-2 based on the same approach used for the operational phase of the Project.

Table 7-3 provides a summary of indirect monitoring technologies to be used for above-zone CO₂ plume and pressure front monitoring during the PISC phase of the Project. This monitoring strategy is consistent with the details and rationale provided in Section 5 – Testing and Monitoring Plan of this application. The results of the monitoring activities will be submitted in the annual report for the year in which they occur and within 30 days of the anniversary date of injection cessation or through an alternate agreed schedule with the UIC Program Director.

Claimed as PBI

Claimed as
PBI

Claimed as
PBI

The analytical methods and quality assurance/quality control measures for collecting and analysis of fluid samples discussed in Section 5 – Testing and Monitoring Plan and will apply to the data collection program of the PISC, as appropriate.

7.4.3 In-Zone CO₂ Plume and Pressure Front Tracking

ExxonMobil proposes to use direct and indirect methods to track the extent of the CO₂ plume and pressure front in the injection zone during the PISC period. Direct monitoring in the injection zone includes continuous pressure and temperature measurements in the final injection zone for Injection Wells No. 01, No. 02, No. 03, and in [REDACTED]

Claimed as PBI

By the start of the PISC phase of the Project, the direct and indirect monitoring activities will

CONFIDENTIAL BUSINESS INFORMATION

have been used for approximately [redacted] and will be a proven set of monitoring technologies for detection monitoring of CO2 plume and brine crossflow potential.

Table 7-4 describes the proposed CO2 and pressure plume tracking methods for the PISC Plan. The water quality and geochemical parameters to be analyzed are presented in Table 7-5, consistent with Section 5 – Testing and Monitoring Plan where additional information on the monitoring methods described and how deviations would be identified.

[redacted]

Monitoring Element	Strategy
Time Period	Immediately following and for up to 50 years from cessation of injection operations.
Monitored Locations, Conditions, and Frequency	• [redacted] • [redacted] • [redacted] • [redacted] • [redacted]
Planned Changes in Monitoring Techniques	None. The model-predicted rapid decrease in CO2 plume movement and pressure significantly reduces the potential for USDW endangerment following injection and eliminated need for additional monitoring.
Triggers	Table 3-21 in Section 3 – Area of Review and Corrective Action Plan provides a list of triggers for the AoR reevaluation process. Those triggers are applicable to the monitoring program.

[redacted]

Claimed as PBI

Claimed as PBI

7.4.4 Submitting PISC Monitoring Results

In accordance with 40 CFR 146.93(a)(2)(iv), ExxonMobil will submit PISC monitoring data to the UIC Program Director in annual reports within 30 days following the anniversary of the date that injection ceases. The annual reports will contain information and data generated during the reporting period, such as:

- A list of monitoring events performed during the reporting period and the associated dates;
- A brief description of sampling/testing/analytical locations, elevations/depths, equipment, and procedures, indicating whether (and why) departures from the procedures specified in the PISC and Site Closure Plan occurred;
- Changes to the monitoring program that took place during the reporting period (e.g., repair to monitoring wells, implementation of approved changes in the frequency of monitoring activities based on criteria established in the PISC and Site Closure Plan and approval of UIC Program Director);
- Synthesis and interpretation of the results that describe trends in parameter values or lack of trends, statistical tests performed, alignment between actual and plume model predictions, the appearance of anomalous or unexpected results, and progress toward attaining the EPA and Railroad Commission of Texas (RRC) criteria for non-endangerment;
- Map(s) and cross section(s) showing the AoR, monitoring locations, and the interpreted extent of the separate-phase CO₂ plume and the pressure front; and
- Any recommended changes to the PISC and Site Closure Plan to continue protection of USDWs.

7.5 Demonstration of Non-Endangerment of USDW

Prior to the approval of the site closure authorization and in accordance with 40 CFR 146.93(b)(2) and 40 CFR 146.93(b)(3), ExxonMobil will provide documentation to assess the potential for USDW to be at risk of endangerment from the CO₂ plume at the end of the PISC phase of the Project. The non-endangerment demonstration will be based on monitoring data and a demonstration that the structure of the confining zones, combined with the geochemical conditions of the subsurface, have effectively permanently sequestered the stored CO₂. This information will be used to demonstrate that additional monitoring is not needed to protect USDW and the Project has met the compliance obligations to receiving authorization for site closure.

This demonstration will be in the form of a detailed report submitted to the UIC Program Director that synthesizes site- and Project-specific information and demonstrates a current understanding of system behavior at the time of the non-endangerment demonstration. The following subsections outline the type of information to be presented in the non-endangerment demonstration report.

ExxonMobil will engage the UIC Program Director as soon as the available data are aligned with the criteria for site closure, which may ultimately be less than the default PISC duration of 50 years pursuant to 40 CFR 146.93(b)(2) and 40 CFR 146.93(c).

7.5.1 Introduction and Overview for Non-Endangerment Demonstration

A summary of relevant background information will be provided in the introduction section, including the operational history of the injection Project, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

7.5.2 Summary of Existing Monitoring Data

The monitoring data collected throughout the Project's lifecycle will be summarized and used to describe how the UCCZ functioned as a barrier to mitigate endangerment of USDW and how the CO₂ is effectively trapped in the injection zones. The non-endangerment demonstration will include a summary of previous monitoring data collected at the site, pursuant to the details in Section 4 – Well Construction Plan and Operating Conditions, and Section 5 – Testing and Monitoring Plan of this application as well as the PISC and Site Closure Plan. Data submittals will be in a format acceptable to the UIC Program Director [40 CFR 146.91(e)] and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of the monitoring infrastructure that has existed at the site. The data will be compared with baseline data collected during site characterization, including the use of statistical analyses as warranted [40 CFR 146.82(a)(6) and 146.87(d)(3)] to assess trends in key parameters that support the proposal for site closure.

7.5.3 Summary of Computational Modeling History

A series of data sources detailed in Section 5 – Testing and Monitoring Plan of this application will be used to update the computational model at least once every five years, more frequently if warranted. The following measured data will be utilized to update the computational model to demonstrate non-endangerment:

- In-zone temperature and pressure data;
- Injection rate and volume data;
- CO₂ plume location based on indirect geophysical monitoring; and
- AZMI data regarding the performance of the UCCZ.

The procedure used to reevaluate the AoR will be based upon the data collected between reevaluations and the well conditions at the time of reevaluation. The post-injection data will include historical injection rates, pressures, pressure fall-off, and historical operational parameters of the three injection wells. ExxonMobil will rely on a process of history matching the plume model results with the actual monitoring data. The measured data will be used as a calibration point for the plume model and the input parameters adjusted to provide a reasonable match between the two data sets. Through this or a similar process, ExxonMobil will provide a validation of the model performance for the CO₂ plume and pressure front.

7.5.4 Evaluation of Reservoir Pressure

The non-endangerment demonstration will include an evaluation of the residual pressure and the potential for future endangerment of USDW continued trends in pressure dissipation. Information will be provided to describe how the pressure and buoyancy effects on plume and pressure migration decayed over time and how the residual levels comply with the requirements for non-endangerment. This evaluation will consider the most-recent AoR delineation/modeling results and pressure monitoring data. The same model that supported the delineation of the AoR or similar approved model by UIC Program Manager will be used for this modeling as it will be verified (or calibrated) by actual monitoring and operational data via AoR reevaluations.

7.5.5 Evaluation of the CO₂ Plume

The evaluation of the CO₂ plume will evaluate the characteristics of the gas-phase CO₂ plume, the aqueous-phase CO₂ plume, and the dissolved-phase CO₂ plume, as appropriate. The evaluation of the potential CO₂ plumes will rely on monitoring data including geochemical and geophysical analyses and the most-recent AoR modeling results. Direct measurements of temperature and pressure of CO₂ in the injection zone as well as the results of geophysical measurements will be used to confirm plume location and demonstrate plume migration rates. A comparison of monitoring data with the most-recent modeling results will also be used to corroborate model predictions of the phase-state of CO₂ and the degree and processes of CO₂ trapping over time.

7.5.6 Evaluation of Emergencies or Other Events

A key feature of the AoR is how few artificial penetrations were identified and of those, o [REDACTED] Claimed as PBI The artificial penetrations of the UCCZ will be [REDACTED] Claimed as PBI and a corrosion resistant cement plug will be placed to restore the integrity of the UCCZ, and additional cement plugs will be set to protect USDW from crossflow potential. If any subsequent artificial penetrations are discovered to have a potential to threaten USDW, they will have been remediated using the same procedures such that no artificial penetrations of concern remain at the time of site closure.

The data and evaluation methods specified pursuant to the requirements of Section 5 – Testing and Monitoring Plan as well as the PISC Plan provide the basis for demonstrating that no future endangerment of USDW is likely to occur.

7.6 Site Closure Plan

ExxonMobil will conduct site closure activities to meet the requirements of 40 CFR 146.93(d) through (h) as described below. ExxonMobil will submit a final Site Closure Plan and notify the UIC Program Director at least 120 days prior of its intent to close the site. Once the UIC Program Director has approved closure of the site, ExxonMobil will plug all injection and monitoring wells and submit a site closure report to the EPA and RRC. The activities, as described below, represent the planned activities based on information provided to EPA. The actual Site Closure Plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site. Additionally, ExxonMobil will record a notation on the deed to the site that the land has been used to sequester CO₂.

Site closure activities will also include removing all surface equipment and restoring the site to its prior land surface condition.

7.6.1 Pre-Closure

In accordance with 40 CFR 146.93(d), a notice of intent to close the site will be submitted to the UIC Director at least 120 days prior to the commencement of closure operations. If any changes are made to the original PISC and Site Closure Plan, a revised plan will also be submitted. Relevant notifications and applications, such as plugging requests, will be submitted and approved by the appropriate agency prior to commencing such activities.

The site closure notice submitted to the UIC Program Director will include the following:

- Facility information, name, and location;
- A list of contact personnel for allowing timely direct communication to resolve any pressing issues; and
- A projected closure date, no less than 120 days following the site closure notification submission, unless the UIC Program Director has approved a different period prior to notice submission.

7.6.2 Plugging Activities

Injection Wells No. 01, No. 02, and No. 03 will be plugged as discussed in Section 6 – Injection Well Plugging Plan. After injection in the injection wells ceases and after the appropriate post-injection monitoring period is complete, the monitoring wells will be plugged and abandoned to meet the requirements at 40 CFR 146.92 and in compliance with applicable state requirements. The plugging procedure and materials will be designed to mitigate fluid movement and protect USDW. Prior to plugging the wells, the necessary procedural revisions to address new information will be submitted to the UIC Program Director for review and approval. The final plugging plans will be submitted to the UIC Program Director no later than 60 days prior to plugging of the wells.

Following receipt of the approved plugging plans, wells below the lowermost USDW and above the UCCZ will be logged and pressure tested to ensure mechanical integrity. If a loss of mechanical integrity is discovered, it will be repaired prior to proceeding with plugging operations. The casing in these wells will be closed in place and it will not be retrieved at abandonment. A combination of permanent packers with plugs and cement on top and cement plugs will be set to plug the wells. All casing strings will be cut at least three feet below ground level. A steel plate, with the required permit information, will be welded to the top of the casing, to the extent required by State of Texas requirements.

7.6.3 Site Restoration

Once the injection and monitoring wells are plugged and abandoned, the surface equipment will be decommissioned and removed from the well site. The well site will be restored to a condition agreed upon with the landowner.

7.6.4 Documentation of Site Closure

Within 90 days of site closure, a final report will be submitted to the UIC Program Director per the requirements of 40 CFR 146.93(f) and will include the following:

CONFIDENTIAL BUSINESS INFORMATION

- Documentation of appropriate injection and monitoring well plugging, including a copy of the survey plats [40 CFR 146.93(f)(1)];
- The survey plat will indicate the locations of the injection wells relative to permanently surveyed benchmarks and will include the location(s) of the monitoring well(s);
- Documentation of well-plugging report will be filed with the RRC [40 CFR 146.93(f)(2)];
- Post-injection monitoring records will be summarized; and
- Records of the nature, composition, and volume of the CO₂ stream for the injection period will be summarized [40 CFR 146.93(f)(3)].

Pursuant to 40 CFR 146.93(g), a record of notation in the Project facilities and infrastructure will be filed on the property deed to provide notice to landowners of the following:

- The land use to sequester CO₂;
- The name of the state agency with which the survey plat was filed (RRC) and the EPA Regional Office (Region VI) at which it was submitted; and
- The total volume of CO₂ injected, the injection zones into which it was injected, and the period over which injection occurred.

As required by 40 CFR 146.93(h), ExxonMobil will retain all records collected during the PISC period for 10 years following site closure. At the end of the retention period, ExxonMobil will deliver all records to the UIC Program Director for retention at a location designated by the UIC Director for that purpose.

-Page Intentionally Left Blank-



Underground Injection Control – Amendment to the Class VI Permit Application for Rose CCS Project Injection Wells No. 01, No. 02, and No. 03

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

Rose Carbon Capture and Storage Project
Jefferson County, Texas
ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2025

SECTION 8 – EMERGENCY AND REMEDIAL RESPONSE PLAN

TABLE OF CONTENTS

8.0	Emergency and Remedial Response Plan	5
8.1	Objectives	6
8.2	Overview of Risk Management Process.....	6
8.3	Identification of Resources/Infrastructure in Area of Review	8
8.4	Identification of Risk Scenarios of Interest	8
8.5	Use of Severity to Define Scope of Response Action	13
8.6	Response Plans for Risk Scenarios	13
8.6.1	Integrity of Injection Well Casing or Cement Seal	13
8.6.2	Integrity of Injection Well Casing or Cement Seal for Legacy Wells	16
8.6.3	Injection Well Monitoring Equipment Failure.....	17
8.6.4	Integrity of the UCCZ.....	20
8.6.5	Induced or Natural Seismic Event	22
8.7	Response Personnel and Equipment.....	23
8.8	Communications Plan and Emergency Notification Procedures	24
8.9	Flood Hazard Risk	24
8.10	Plan Review	25
8.11	Staff Training and Exercise Procedures	25

List of Tables

Claimed as PBI

List of Figures

Claimed as PBI

Appendix G – FEMA Maps

Claimed as PBI

-Page Intentionally Left Blank-

8.0 Emergency and Remedial Response Plan

On March 7, 2024, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) submitted an Underground Injection Control (UIC) Class VI permit Application (Application) to the U.S. Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage Project (Project). ExxonMobil is undertaking the Project in Jefferson County, Texas to sequester a [redacted] of carbon dioxide (CO₂) using three injection wells over an injection period of up to [redacted]. The predicted total CO₂ storage is [redacted]. An Emergency and Remedial Response Plan (ERRP) was submitted in the Application in compliance with the requirements of the Code of Federal Regulations, Title 40, Section 146.94 [40 CFR 146.94]. A revision to the ERRP was prepared for the amendment to update the actions to be taken to address events that may cause endangerment to underground sources of drinking water (USDWs) during the construction, operation, and post-injection site care periods of the Project. Under 40 CFR 146.90(g), the actions described in the ERRP are to be implemented immediately to address a very low-likelihood event where the movement of the injection fluid or formation fluid endangers USDW. ExxonMobil prepared this ERRP to provide both the scope of actions to be taken and the schedule under which the actions would be implemented.

Since the submittal of the Application, ExxonMobil obtained a substantial amount of new data and analyses from the core sampling and analysis program for the Project's stratigraphic well ([redacted]). The major changes to the Application are based on incorporating the recently obtained data into the Area of Review (AoR) model and updates to the extent of the CO₂ plume and critical-pressure front and the operating strategy for CO₂ storage. [redacted]

[redacted] In turn, these changes have required updates to the ERRP that included the removal of phased-corrective action costs for [redacted]

[redacted]

ExxonMobil has already created a number of engineering design and planning safeguards to reduce the potential for the occurrence of a very low-likelihood emergency and remedial response event. These steps are based on ExxonMobil's global experience and expertise with risk management in site selection, well drilling and completion, and reservoir operations. The risk management approach is evident in the preparation of sections of this UIC Application. Section 2 – Site Characterization describes how the geologic setting is favorable to safe CO₂ sequestration because of the favorable injection zone and confining zone characteristics that exist at the site. Section 3 – Area of Review and Corrective Action describes how the CO₂ plume and pressure front are predicted to be confined to the injection zone and how pressure will be managed to reduce the potential for leakage to USDWs. [redacted] artificial penetrations through the confining zones will be remediated to safeguard USDWs within the AoR before operations commence. Section 4 – Well Construction Plan and Operating Conditions describes how the well design process and operating controls for mechanical integrity and pressure control to maintain a high level of risk reduction for the Project. Lastly, Section 5 – Testing and Monitoring Plan, provides the data acquisition plan for tracking the CO₂ plume and brine pressure front to assess compliance with control and containment requirements.

The purpose of this section is to provide the elements of the risk management process undertaken for the Project so that the UIC Program Director can ultimately approve the remedial and response actions in advance. Once approved, ExxonMobil will be prepared to implement the actions necessary to facilitate and expedite response efforts for the very low likelihood possibility of a leak occurring from the injection zone. The ERRP will apply over the life of the Project, including throughout the post-injection site care period [40 CFR 146.94(a)].

8.1 Objectives

The ERRP identifies a set of hypothetical potential risk scenarios under which there may be an endangerment to USDWs and the actions to be taken to mitigate such risk. The objectives of the ERRP are aligned with the requirements of 40 CFR 146.94, which include:

- Identify potential risk scenarios and adverse events that could impact USDW in the AoR. The assessment focuses on those events that were found to have a combined probability and consequence that makes them more likely to have an impact than other factors.
- Provide a description of the response actions necessary to reduce the potential consequences to USDWs. For each scenario considered to be of material concern, describe the anticipated severity of the event, the phase during which the event could occur (i.e., construction, injection and/or post-injection phases), the proposed avoidance measures, what methods will detect the loss of containment or control, the response actions, notification requirements, and personnel and equipment that would be employed to mitigate the risk; and
- Provide contact information for response personnel, a communications plan, and a description of staff training and exercise procedures.

8.2 Overview of Risk Management Process

ExxonMobil took the findings from the site characterization, AoR, and corrective action sections of the Application and identified hypothetical risk scenarios that could pose a potential threat to USDWs in the low likelihood event of occurrence. ExxonMobil's risk assessment process was used to estimate the probability and consequence of each risk scenario based on the experience and judgment of the risk subject matter experts for the Project. The list was sorted from the most probable and consequential risk scenario to the least probable and consequential scenarios so that the critical scenarios and the response actions to be undertaken could be identified.

As shown in Figure 8-1 below, the maximum anticipated risk level for the Project, including the combination of the selected risk scenarios for the ERRP, is within the medium risk category. As mentioned above, several risk management steps were already taken to address the potential for CO₂ or brine migration to occur.

Claimed as PBI

Claimed as PBI

The potential for these features in the UCCZ to become a migration pathway for a release of CO₂ were mitigated by planning for the following actions described in the Application:

- Artificial penetrations through the UCCZ will be re-abandoned to restore containment integrity at each artificial penetration location where the potential for elevated crossflow risk was identified;
- The maximum injection pressure will be maintained below the potential hydraulic fracturing or activation pressure of a natural fault to mitigate the potential for CO₂/brine leaks through seal(s) due to mechanical fracturing or migration of CO₂/brine along faults;
- State-of-the-art injection well and monitoring well construction methods and mechanical integrity testing (MIT) will be employed to reduce the potential for the loss of internal or external mechanical integrity, which could potentially release CO₂ to USDWs or the atmosphere;
- The composition of the injectate stream will be managed and monitored such that unexpected reactions with the potential to impact containment are mitigated;
- CO₂ plume and pressure front tracking will be undertaken using a combination of direct and indirect measurements and reported semiannual for review and consideration in AoR reevaluations, at a minimum frequency of every five years; and

- The predictive reservoir modeling will be calibrated and verified using monitoring data to identify the potential for the CO2 plume and pressure front to encounter artificial penetrations that have the potential for CO2 or brine crossflow from the injection intervals to the lowermost USDW and take preventive measures before such an event could occur.

8.3 Identification of Resources/Infrastructure in Area of Review

[REDACTED]

Claimed as PBI

The infrastructure development is primarily in the form of county roads and power transmission lines to service the few developed areas.

The water resources in the vicinity of the Project that may be affected by a very low-likelihood CO2 or brine leakage event that could endanger USDW include water wells completed in the Chicot and Evangeline Aquifers above a depth of approximately [REDACTED].

Claimed as PBI

[REDACTED], which is the lowermost USDW within the AoR.

[REDACTED]

Claimed as PBI

[REDACTED]

As shown on Figure 8-2, one water conveyance canal was identified as [REDACTED].

Claimed as PBI

[REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

8.4 Identification of Risk Scenarios of Interest

Through the risk assessment process, the following list of scenarios were considered of sufficient probability and consequence to warrant development of response action plans. Other scenarios were considered but were found to have relatively low probability and consequence factors and thus do not warrant further consideration at this time. As shown below, a total of nine risk scenarios were considered for the ERRP.

Claimed as PBI

Claimed as
PBI

-Page Intentionally Left Blank-

Claimed as PBI

-Page Intentionally Left Blank-

8.5 Use of Severity to Define Scope of Response Action

Response actions were developed for each of the nine hypothetical risk scenarios identified for the ERRP. As listed in Table 8-2, the severity of the risk scenario was fit to a three-tiered categorization of emergency conditions. In addition, the response actions envision a stage-gate process where the information regarding the degree of severity for the emergency condition is evaluated to align the appropriate level of response to bring about mitigation of the emergency event.

Table 8-2: Degrees of Risk for Emergency Events

Emergency Condition	Definition
Major emergency	Events pose immediate substantial risk to USDWs and indirectly from USDW endangerment to resources or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) must be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to USDW and indirectly from USDW endangerment to resource or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to USDW, resources, or infrastructure.

In accordance with 40 CFR 146.94(b), for the events below, if the injected CO₂ stream and associated brine pressure front may cause an endangerment to a USDW, each set of response actions start with immediately ceasing injection and notifying the UIC Program Director within 24 hours of the confirmation of a release event and the intention to implement the appropriate response action in the ERRP.

8.6 Response Plans for Risk Scenarios

The following response action details are provided to have a pre-approved set of actions in place should measurements collected pursuant to the Section 5 – Testing and Monitoring Plan indicate a malfunction or deviation from permitted limits.

8.6.1 Integrity of Injection Well Casing or Cement Seal

Two hypothetical release mechanisms were identified for injection wells that could possibly result in a release of CO₂ and/or brine to USDWs. CO₂ could be detected at an injection well, implying that internal or external mechanical integrity of an injection well may have been compromised and released CO₂ to USDWs. CO₂ or brine could also be released to USDW at the injection well because of subsurface cement degradation or annular space defects in cement completion.

Hypothetical Release Mechanism: mechanical integrity failure at injection well resulting in release of CO ₂ and/or CO ₂ and/or brine to USDWs.
Severity:
Minor: A malfunction in the monitoring equipment created a false positive indication of a release when in fact none occurred. Alternatively, detection monitoring equipment at the wellhead facility detects the release and the well was shut-in, representing a minor CO₂ release.

CONFIDENTIAL BUSINESS INFORMATION

• Serious: A failed MIT identified a release mechanism, but detection of brine or CO2 was not apparent in the detection monitoring system.
• Major: A detection of CO2 and/or brine to USDW within the AoR prior to confirming the source of the injection well release point.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Proper wellbore design, including the use of corrosion resistant cement and CO2 compatible metallurgy of the casing and tubing, will be used for construction of the injection well.
• Routine inspection of the well casing and cement integrity to identify potential corrosion or deficiencies.
Detection methods:
• Deficiency identified during continuous pressure and temperature monitoring, pressure falloff tests, and annulus pressure tests.
• Wellhead pressure exceeds the maximum pressure specified in the permit.
• Annulus pressure indicates a loss of external or internal integrity/containment.
• CO2 plume and pressure tracking above UCCZ indicates a change in conditions.
• Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
• MIT identifies a potential issue in the integrity of the well.
• Well casing and cement bond logs conducted during shut-ins to assess loss decay or corrosion more than acceptable limits.
Response actions:
• Notify ExxonMobil Site Manager and site personnel.
○ The Site Manager will respond to the event for an initial assessment to determine severity of event.
• Minor Event:
○ [REDACTED]
Claimed as PBI
[REDACTED]

○ [REDACTED]
Claimed as PBI
• Serious or Major Event:
○ [REDACTED]
Claimed as
PBI
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-

CONFIDENTIAL BUSINESS INFORMATION

treatment professionals.

Equipment: Drill rig, logging equipment for cement or casing materials, MIT equipment, environmental media sampling equipment, well plugging equipment.

8.6.2 Integrity of Injection Well Casing or Cement Seal for Legacy Wells

Consistent with the potential for CO₂ or brine to migrate to USDW at an injection well, artificial penetrations of the UCCZ from legacy oil and gas activities may provide a similar risk scenario. Legacy wells were identified within the AoR that penetrate the UCCZ. The plugging of legacy wells will be completed as a corrective action prior to operation. The objective of this risk scenario is to provide the response actions in the event that unknown legacy wells are found and suspected of CO₂ and/or brine leakage to USDWs as a result of potential casing or cement integrity issues in the AoR.

Hypothetical Release Mechanism: CO₂ and/or brine migrate to USDW at an artificial penetration as detected within the AoR.

Severity:

- Minor: direct and indirect CO₂ plume and pressure front tracking indicate that the legacy well is in the path of migration with the potential to create elevated pressures and a potential for corrosive environment to be created at the well location.
- Serious: direct and indirect CO₂ plume and pressure front tracking indicate that the legacy well has been impacted with minor increases of CO₂ and/or brine pressures and corrosive fluids.
- Major: direct and indirect CO₂ plume and pressure front tracking indicate that the legacy well has been impacted by significantly elevated pressures and a corrosive environment is present that could create a crossflow potential between the injection zone and USDW if a conduit were present.

Timing of event: Injection and/or post-injection phase.

Avoidance measures:

- Compliance with CO₂ plume and brine tracking systems.
- Plume model updates to predict pressure front arrival times at legacy well locations and adjust timing of phased-corrective action.

Detection methods:

- CO₂ plume and pressure tracking indicates impact is likely.
- Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
- Well re-entry to collect casing and cement bond logs to assess integrity and well completion materials.

Response actions:
For minor severity: [REDACTED]
Claimed as PBI
For major and serious events:
• [REDACTED]
[REDACTED]
Claimed as
[REDACTED]
PBI
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
[REDACTED]
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment for cement or casing materials, MIT equipment, environmental media sampling equipment, well plugging equipment.

8.6.3 Injection Well Monitoring Equipment Failure

Loss of mechanical integrity of well pressure equipment may occur during operation of the injection wells. A pressure gauge malfunction or other similar equipment could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO₂/brine crossflow to USDW by fault or fracture activation or well casing and/or cement failure in the vicinity of the

CONFIDENTIAL BUSINESS INFORMATION

production casing perforations.

Hypothetical Release Mechanism: Loss of mechanical integrity of well pressure equipment could create a shut-off valve malfunction and result in an uncontrolled pressure situation and CO2/brine crossflow to USDW by fault or fracture activation or by well casing and/or cement failure in the vicinity of the production casing perforations.
Severity:
• Minor: Failure of monitoring equipment to document compliance with permit operating conditions, but subsequent evaluation of available information demonstrates that well integrity has not been impacted.
• Serious/Major: Failure of monitoring equipment to document permit operating conditions and subsequent evaluation of the data documents non-compliance with permitted operating conditions and potential for well integrity impacts.
Timing of event: Injection phase and/or post-injection phase.
Avoidance measures:
• Routine equipment inspection and maintenance to identify potential integrity issues that may be a result of equipment failure.
• Routine inspections and calibration of monitoring equipment in accordance with manufacturers recommended procedures.
• Consistent fluid sampling throughout the detection monitoring well network to detect a release above the UCCZ.
• Redundant pressure and temperature measurements in the injection zones to confirm compliance with permitted operating conditions.
Detection methods:
• Anomalies in pressure and rate monitoring, pressure falloff tests, and annulus pressure tests.
Response actions:
• Notify ExxonMobil Site Manager and site personnel.
○ The Site Manager will respond to the event for an initial assessment to determine severity of event.
• Notify the UIC Director within 24 hours per 40 CFR 146.91(c).
• Determine the cause and severity of failure to determine if the CO2 stream or formation fluids may have been released into any unauthorized zone.

- For a Minor emergency [REDACTED]
Claimed as PBI

- [REDACTED]

- [REDACTED]

- [REDACTED]

- For a Major or Serious emergency [REDACTED]
Claimed as PBI

- [REDACTED]

- [REDACTED]

- [REDACTED]

- [REDACTED]

- [REDACTED]

- [REDACTED]

- [REDACTED]

• [REDACTED]
Claimed as PBI
Claimed as PBI
Claimed as PBI
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.
Equipment: Drill rig, logging equipment, cement or casing materials, and air and water testing equipment.

8.6.4 Integrity of the UCCZ

Several potential risk scenarios were considered that involve a hypothetical release through naturally occurring faults and fractures or penetration of the UCCZ, creating a migration pathway toward USDW. For example, CO₂ could hypothetically leak through natural faults or fractures in the UCCZ within or beyond the AoR and impact USDWs. CO₂ or brine could hypothetically migrate horizontally to artificial penetrations within or beyond the AoR that are not sealed at the UCCZ and result in a release to USDWs. Response actions were developed to address such scenarios in the very low-likelihood event that they occur.

The primary limiting factor for the magnitude of the release for these scenarios was based on the site characteristics described in Section 2 – Site Characterization. CO₂ and brine leaks through shales due to mechanical fracturing were not considered a material concern for the Project because of the physical nature of the confining shale materials. Above the UCCZ is approximately [REDACTED] Claimed as PBI of saturated shale, mudstone, and sand. Such a release would likely be detected by the detection monitoring program for groundwater prior to release to the surface. Therefore, ambient air monitoring in the AoR was contingent on the confirmed release of CO₂ to USDW at sufficient concentrations to migrate to the surface at levels above health-based thresholds.

The following response actions were developed to mitigate the potential for releases through the UCCZ, which were assumed to occur during injection operations and/or post-injection site care.

Hypothetical Release Mechanism: release through naturally occurring faults and fractures or penetration of the UCCZ, creating a migration pathway toward USDWs.
Severity:
• Minor: direct and indirect CO₂ plume and pressure front tracking indicate that a fault or fracture is in the path of migration with the potential to create elevated pressures sufficient to cause crossflow above the UCCZ.

CONFIDENTIAL BUSINESS INFORMATION

• Serious: direct and indirect CO2 plume and pressure front tracking indicate that a fault or fracture has been impacted with minor increases of pressures.
• Major: direct and indirect CO2 plume and pressure front tracking indicate that a fault or fracture has been impacted by significantly elevated pressures that will likely create a crossflow potential between the injection zone and USDW.
Timing of event: Injection and/or post-injection phase.
Avoidance measures:
• Compliance with CO2 plume and brine tracking systems.
• Plume model updates to predict pressure front arrival times at fault and fracture locations and adjust timing of phased detection monitoring programs elements.
Detection methods:
• CO2 plume and pressure tracking indicates impact is likely.
• Fluid samples from above the UCCZ and USDW indicate a statistically significant change in conditions.
• Third-party direct or indirect data confirm impact to fault, fracture, or artificial penetration outside of AoR.
Response actions:
• If the detection monitoring program outline in the Section 5 – Testing and Monitoring Plan or similar third-party monitoring program detects a confirmed release of CO2 or brine through the UCCZ to the first water-bearing zone above the UCCZ or USDW, notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
• Determine the severity of the event, based on the information available, within 24 hours of notification.
• For all emergencies (Major, Serious, or Minor):
• [REDACTED]
• [REDACTED]
• [REDACTED]
• [REDACTED]

■	[REDACTED]
■	[REDACTED]
■	[REDACTED]
■	[REDACTED]
■	[REDACTED]
■	[REDACTED]
■	[REDACTED]
■	[REDACTED]
Personnel: Emergency response personnel, geotechnical professionals, and environmental or water-treatment professionals.	
Equipment: Drill rig, logging equipment, cement or casing materials, and air and water testing equipment.	

8.6.5 Induced or Natural Seismic Event

Natural or induced seismic events of sufficient magnitude to create damage were found to be highly improbable for the site location and under permitted operating conditions that are below the critical fracture pressure. In the very low-likelihood chance that such seismic conditions occurred, the consequences could be of significance regarding the integrity of the artificial penetrations of the UCCZ and the natural faults and fractures. Therefore, the following response actions were developed to gather information regarding the potential for CO₂ and brine confinement issues to arise under such events.

ExxonMobil will rely upon U.S. Geologic Survey seismic monitoring data for the site and surrounding area to provide information on a seismic event, should one occur. If a review of the data indicates that the event was more likely than not associated with the injection zone in or near the AoR, ExxonMobil will notify the UIC Program Director of the intent to install a site-specific network of seismic stations to provide additional information with the regional seismic data. The details of the site-specific seismic monitoring system will be provided to the UIC Program Director as a modification of Section 5 – Testing and Monitoring Plan. Table 8-3 provides the response actions depending on severity of the seismic event.

Claimed as PBI

8.7 Response Personnel and Equipment

Site personnel, Project personnel, and local authorities will be relied upon to implement this ERRP and will be dispatched in the case of an emergency. In the event of an emergency, appropriate city, county, and state emergency responders and agencies may be notified based on severity of the risk. Contact information for ExxonMobil Emergency Authorities and state and local emergency services are outlined in Table 8-4 and Table 8-5, respectively.

A site-specific emergency contact list will be developed and maintained during the life of the Project. ExxonMobil will provide the current site-specific emergency contact list to the UIC Program Director.

Claimed as PBI

Table 8-5: Emergency Services

Agency	Telephone Number
Beaumont Fire and Rescue Station 1	911 or (409) 880-3901
Jefferson County Sheriff	911 or (409) 835-8411
Jefferson County Public Health Unit #1	(409) 835-8530
Jefferson County Office of Emergency Management	(409) 835-8757
Texas Division of Emergency Management	(512) 424-2208
Texas Department of Public Safety	(512) 424-2000
State of Texas Spill-Reporting Hotline	1-800-832-8224
Texas Parks and Wildlife Department	(512) 389-4800
EPA Region 6	800-887-6063 or 214-665-2760
EPA Class VI Contact – Brandon Maples	214-665-7252
Texas Department of Natural Resources	(512) 389-4800
Jefferson County Local Emergency Planning Committee	(409) 835-8757
National Response Center	1-800-424-8802
State of Texas Spill-Reporting Hotline	1-800-832-8224
EPA National Response Center (24 hours)	(800) 424-8802

Necessary equipment for emergency and remedial response may vary depending on the event. Generally, no specialized equipment will be required for response actions (such as cessation of injection, well shut-in, and evacuation). If specialized equipment (such as a drilling rig or logging equipment) is required, ExxonMobil will be responsible for its procurement.

8.8 Communications Plan and Emergency Notification Procedures

As appropriate, ExxonMobil will communicate to the relevant public authorities about an event that may require emergency response so that the public understands the emergency event and if there are any environmental, health, or safety concerns. Based on the emergency event, ExxonMobil will determine the appropriate information, timing, and communication method for the event. This information may include potential impact of the event on drinking water or the severity of the event, actions taken or planned to address the event, and other information needed to protect the public during the event.

If required, ExxonMobil will also communicate with other entities who may need to be informed about or act in response to the event. These may include local water purveyors or operators, CO2 suppliers, pipeline operators, oil and gas operators, landowners, and other departments or authorities as guided by the UIC Program Director.

8.9 Flood Hazard Risk

Injection Wells No. 01, No. 02, and No. 03 and the surrounding area are designated as Federal

Emergency Management Agency flood hazard zone X (unshaded). Flood hazard zone “X” (unshaded) corresponds to areas determined to be outside of the 500-year floodplain. This zone is an area of minimal flood hazard, which is higher than the elevation of the 0.2-percent-annual-chance flood. The well locations and Federal Emergency Management Agency flood zones are shown in Appendix G.

8.10 Plan Review

The UIC Program Director will evaluate this proposed ERRP to verify that ERRP meets the requirements of 40 CFR 146.94(a) and that the plan accounts for all site-specific conditions. The approved ERRP is enforceable, whether or not it is a condition of the permit, because the plan itself and UIC Program Director’s approval are required by the Class VI Rule [40 CFR 146.93(a)].

This ERRP shall be reviewed:

- At least once every five years following its approval by the permitting agency [40 CFR 146.94(d)].
- Within one year of any AoR reevaluation [40 CFR 146.94(d)(1)].
- Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director [40 CFR 146.94(d)(2)]; or
- When required by the Director [40 CFR 146.94(d)(3)].

If the review indicates that no amendments to the ERRP are necessary, ExxonMobil will provide the permitting agency with the documentation supporting the “no amendment necessary” determination. If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within 30 days following an event that initiates the ERRP review procedure.

The amended plan must be approved by the UIC Program Director and would then be incorporated into the Class VI Permit. If significant changes to the plan are needed, the UIC Program Director may need to modify the permit. A permit modification under 40 CFR 144.39 would require notification of the public and an opportunity for comment. Minor changes to the plan, as defined under 40 CFR 144.41, do not require a permit modification or a public process under 40 CFR Part 124.

8.11 Staff Training and Exercise Procedures

Personnel will be trained in their duties and responsibilities related to these facilities. Emergency Response Drills will be conducted annually via simulated onsite or table-top scenarios. All plant personnel, visitors, and contractors must complete a plant overview orientation before entering the facilities. ExxonMobil will coordinate with local mutual aid emergency responders over the potential hazards and response scenarios of the site.

-Page Intentionally Left Blank-



Underground Injection Control – Amendment to Class VI Permit Application for Rose CCS
Project Injection Wells No. 01, No. 02, and No. 03

SECTION 9 – FINANCIAL ASSURANCE

Rose Carbon Capture and Storage Project
Jefferson County, Texas
ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2025

SECTION 9 – FINANCIAL ASSURANCE

TABLE OF CONTENTS

9.0	Financial Assurance	5
9.1	Facility Information.....	5
9.2	Financial Assurance Demonstration.....	6
9.3	Estimated Coverage Amounts	8
9.4	Corrective Action	9
9.5	Well Plugging.....	10
9.5.1	Injection Well Plugging	10
9.5.2	Monitoring Well Plugging.....	10
9.6	Post-Injection Site Care and Site Closure Plan	11
9.6.1	Post-Injection Monitoring.....	11
9.6.2	Site Closure Plan	11
9.7	Emergency and Remedial Response	12

List of Tables

Claimed as PBI

List of Figures

Claimed as PBI

Appendix J – Financial Assurance

Claimed as PBI

-Page Intentionally Left Blank-

9.0 Financial Assurance

On March 7, 2024, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) submitted an Underground Injection Control (UIC) Class VI Permit Application (Application) to the U.S. Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage (CCS) Project (Project). ExxonMobil is undertaking the Project in Jefferson County, Texas to sequester a [REDACTED]

he predicted total CO₂ storage is [REDACTED]. Under the Code of Federal Regulations, Title 40, Section 146.85 [40 CFR 146.85], owners or operators of geologic sequestration (GS) injection wells are required to demonstrate financial responsibility for GS activities.¹ Consistent with these regulatory requirements, ExxonMobil has prepared this document to demonstrate financial responsibility for the injection wells that comprise the Rose CCS Project (Rose Site²).

Since the submittal of the Application, ExxonMobil obtained a substantial amount of new data and analyses from the core sampling and analysis program for the Project's stratigraphic well [REDACTED]. The major changes to the Application are based on incorporating the recently obtained data into the Area of Review (AoR) model and updates to the extent of the CO₂ plume and critical-pressure front and the operating strategy for CO₂ storage. [REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

[REDACTED]

The sections that follow summarize the Project's GS activities, as well as the qualifying financial instrument that ExxonMobil proposes to use, to demonstrate financial responsibility for the following Project phases: (1) Corrective Action; (2) Injection Well Plugging; (3) Post-Injection Site Care (PISC) and Site Closure; and (4) Emergency and Remedial Response (ERR).

9.1 Facility Information

Facility Name: ExxonMobil Low Carbon Solutions Onshore Storage LLC
(ExxonMobil) – Rose CCS Project

Facility Contact: [REDACTED]
ExxonMobil Low Carbon Solutions Onshore Storage LLC

¹ The use of the term “geologic sequestration activities” is unique to this section of the Application. It is used to provide additional clarity on which activities of the Project's lifecycle necessitate financial assurance from those that do not, consistent with EPA guidance for financial assurance.

² Reference to the Project as the “Rose Site” is used in this section of the Application to distinguish between this Project and other future ExxonMobil project applications undergoing simultaneous financial assurance review.

CONFIDENTIAL BUSINESS INFORMATION

Project Site Name: Rose Carbon Capture and Storage Project

Project Location: Jefferson County, Texas

Well Name and Number [Redacted] (Rose CCS Project Injection Well No. 01)

County Jefferson

Location (RR D, S, A)

Latitude / Longitude (NAD83)

API

Claimed as PBI

Well Name and Number [Redacted] (Rose CCS Project Injection Well No. 02)

County Jefferson

Location (RR D, S, A)

Latitude / Longitude (NAD83)

API

Claimed as PBI

Well Name and Number [Redacted] (Rose CCS Project Injection Well No. 03)

County Jefferson

Location (RR D, S, A)

Latitude / Longitude (NAD83)

API

Claimed as PBI

9.2 Financial Assurance Demonstration

Per 40 CFR 146.85(a)(1)(v), ExxonMobil requests approval from the UIC Program Director, or their designee, to use a corporate guarantee from Exxon Equity Holding Company (EEHC) for purposes of demonstrating financial responsibility for Corrective Action, Injection Well Plugging, PISC and Site Closure, as well as ERR. EEHC is an indirectly wholly owned subsidiary of Exxon Mobil Corporation (EMC). EEHC provides financial support to or on behalf of EMC's affiliates. EEHC maintains significant intercompany relationships with EMC and its affiliates as shown in Figure 9-1, and as of December 31, 2023, the company had interest-bearing deposits with EMC and its affiliates totaling [Redacted]. The deposit balances are current and can be called upon demand. See Appendix J-1 for a copy of the independently audited financial statements for EEHC.

Claimed as PBI

In support of the financial assurance demonstration, EEHC has provided a corporate guarantee to ExxonMobil, which is consistent in form to the corporate guarantee language included in Appendix B of the EPA's July 2011 guidance document (EPA, 2011). See Appendix J-2 for a copy of the executed corporate guarantee. As shown in Table 9-1, EEHC satisfies both Part 1 and Part 2 of the corporate financial test criteria in 40 CFR 146.85(a)(6)(v).

Table 9-1: Financial Coverage and Threshold Criteria for EEHC, as Guarantor to ExxonMobil for the Rose Site

Financial Coverage / Threshold Requirement per 40 CFR 146.85(a)(6)(v) ³		EEHC Financial Measure
Part 1		
1. Tangible net worth of at least \$100 million? ⁴		Claimed as PBI
2. Net working capital at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR costs?		
3. Tangible net worth of at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR costs?		

³ As stated in Note 3 of EEHC's independently audited financial statements, *Deposits receivable from Exxon Mobil Corporation and affiliates* are current and can be called upon demand. All other assets were considered "non-current" for the purposes of this analysis. In addition, all liabilities were considered "current" since the audited financial statements do not differentiate current from non-current liabilities.

⁴ ExxonMobil recognizes that 40 CFR 146.85(a)(6)(v) requires that its guarantor meet a Tangible Net Worth of an amount approved by the UIC Program Director. For purposes of this financial assurance demonstration, EEHC affirms that it maintains a Tangible Net Worth of at least \$100 million, per the recommended threshold included in EPA's July 2011 Class VI financial responsibility guidance (p. 15).

CONFIDENTIAL BUSINESS INFORMATION

Financial Coverage / Threshold Requirement per 40 CFR 146.85(a)(6)(v) ³	EEHC Financial Measure
4. Assets in the United States amounting to at least 90% of total assets <u>or</u> Assets in the United States amounting to at least six times the sum of the current corrective action, well plugging, PISC and site closure, and ERR cost estimate?	Claimed as PBI
Part 2	
5. Total liabilities to net worth ratio less than 2.0?	
6. Current assets to current liabilities ratio greater than 1.5?	
7. Sum of net income plus depreciation, depletion, and amortization to total liabilities ratio greater than 0.1?	
8. Current assets minus current liabilities to total assets ratio greater than <i>minus</i> 0.1?	
9. Net profit (revenues minus expenses) greater than \$0?	

Appendix J-3 is a completed letter from [REDACTED] of EEHC, serving as the chief financial officer of EEHC, that demonstrates the company's ability to meet the requisite financial coverage and threshold criteria, per 40 CFR 146.85(a)(6)(v).

Appendix J-3 is consistent in form to the "Letter from Chief Financial Officer" included in Appendix B of the EPA's July 2011 guidance document.⁵

Consistent with the EPA's July 2011 guidance, ExxonMobil provides this demonstration of fiscal responsibility with the understanding that the financial instruments referenced herein will be updated and verified no less than annually. As each GS activity phase is initiated, ExxonMobil will confirm that the coverage limits provided by the respective financial responsibility instruments are sufficient to cover the corresponding costs prior to initiating the Project phase.

9.3 Estimated Coverage Amounts

The total current cost estimate for the Project's GS activities necessitating financial assurance at the Rose Site is [REDACTED] in 2025 dollars. This total cost estimate assumes the hiring of independent, third-party contractors to perform the required activities for each Project phase.

The cost estimate is separated into the following phases:

Claimed as PBI

⁵ *op.cit.* See B-19 Appendix B: Recommended Financial Responsibility Instrument Language (Forms/Templates).

□ Financial responsibility coverages for well plugging reflect the current estimated cost for plugging the three injection wells and four monitoring wells related to the Project.

Table 9-2 summarizes the total estimated cost of performing each GS activity, along with the timeline for which financial assurance coverage is expected to be needed. The values included in this demonstration of financial responsibility are based on cost estimates developed as part of the Application process and assume the hiring of third-party contractors to perform the services or to procure the goods associated with the performance of each GS activity. These values are subject to change during the life of the Project to account for inflation of costs and changes to the Project that may affect the cost of covered activities. Per 40 CFR 146.85(c), during the active life of the Project, ExxonMobil will adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial assurance instrument. In addition, ExxonMobil will provide to the UIC Program Director written updates of adjustments to the cost estimate within 60 days of any amendments to the AoR and Corrective Action Plan [40 CFR 146.84], the injection well plugging plan [40 CFR 146.92], the PISC and Site Closure Plan [40 CFR 146.93], and the emergency and remedial response plan (ERRP) [40 CFR 146.94].

ExxonMobil will adjust the value of its financial assurance instruments in response to any changes in cost estimates and will resubmit its revised demonstration of financial responsibility to the UIC Program Director or their designee for review and approval. ExxonMobil will not adjust the established coverage values of any financial assurance instrument without prior approval from the UIC Program Director, or their designee.

Claimed as PBI

9.4 Corrective Action

The Corrective Action Plan is discussed in detail in Section 3 – Area of Review and Corrective Action Plan. Per the requirements of 40 CFR 146.84, the plan specifically outlines both a plugging plan for the artificial penetrations found within CO₂ plume and brine pressure front and the recompletion schedule whereby the wellbore modifications will have been completed.

For the planned activities at the Project, workovers on the legacy wells found to have sufficient deficiency as to represent a potential loss of CO₂ or brine containment will be re-entered and plugged prior to receiving approval to inject from the UIC Program Director. [REDACTED]

Claimed as PBI [REDACTED] The estimated financial assurance coverage value for this GS activity is shown in Table 9-3.

Per 40 CFR 146.84(a)(5)(ii), this financial responsibility demonstration will be updated annually to account for any changes in expected financial coverage values and to confirm that the financial instrument(s) then in place remain adequate for use.

Claimed as PBI

9.5 Well Plugging

9.5.1 Injection Well Plugging

Plugging and abandonment (P&A) of the injection wells at the Project will meet the requirements of 40 CFR 146.92. The P&A plan for the injection wells was designed to reduce the potential for movement of CO₂ or brine from the injection interval through the [redacted] and toward underground sources of drinking water (USDWs).

A detailed P&A plan is discussed in Section 6 – Injection Well Plugging Plan. In alignment with the requirements for the P&A plan, the estimated financial assurance coverage value includes costs for logs/wireline to be run in the wellbore before cementing occurs, if necessary. CO₂-compatible cement will be used to set the cement plug for the first [redacted], followed by additional plugs at the base of the lowermost USDW and at the well surface. The expenses relating to personnel and equipment have been accounted for in Table 9-3.

9.5.2 Monitoring Well Plugging

P&A of the [redacted] associated with the Project will also meet the requirements of 40 CFR 146.92. As detailed in Section 6 – Injection Well Plugging Plan, the P&A of the monitoring wells was designed to protect USDW from potential endangerment. The estimated financial assurance coverage value for this GS activity includes the costs for logs and wireline to be run in the in-zone monitoring well before cementing occurs to the extent necessary. The expenses relating to personnel and equipment have been accounted for in Table 9-4.

Claimed as PBI

Claimed as PBI

9.6 Post-Injection Site Care and Site Closure Plan

The PISC and Site Closure Plan has been designed to meet the requirements of 40 CFR 146.93. The estimated financial assurance coverage value for this GS activity includes the cost categories summarized in Table 9-5, while the plan itself is discussed in Section 7 – Post-Injection Site Care and Site Closure Plan.

9.6.1 Post-Injection Monitoring

As discussed in Section 5 – Testing and Monitoring Plan, Claimed as PBI and pressure and temperature monitoring will be conducted during operation and after the end of injection to assess the integrity of the well and to track the migration of the CO₂ plume and brine pressure front.

9.6.2 Site Closure Plan

Site closure will occur when the UIC Program Director has released the owner from PISC duties and the demonstration of non-endangerment for USDWs has been approved. The estimated financial assurance coverage value for this GS activity is summarized in Table 9-5 and reflects the expected amount to decommission and close the site.

Table 9-5: Summary of Estimated PISC and Site Closure Costs Underpinning Financial Assurance Coverages

Claimed as PBI

Claimed as PBI

9.7 Emergency and Remedial Response

The ERRP is discussed in Section 8 – Emergency and Remedial Response Plan and is designed to satisfy the requirements of 40 CFR 146.94, which necessitates an ERRP that describes actions ExxonMobil will take to address movement of injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and PISC periods.

The financial assurance coverage value for ERR is estimated to be [redacted] in 2025 dollars and is summarized in Table 9-6. This estimate assumes coverage for the following event-based risk activities at the Project: mechanical integrity of injection well casing or cement seal, artificial penetrations of the [redacted], mechanical integrity of operating equipment, and natural features affecting sealing properties of the [redacted]. Details regarding the approach used to develop the risk-based scenarios, the levels of severity considered, and the actions to be taken to avoid, monitor, respond, and notify the occurrence of risk events are summarized in detail in Section 8.

Table 9-6: Summary of Estimated ERR Costs Underpinning Financial Assurance Coverages

Claimed as PBI



Underground Injection Control – Amendment to Class VI Permit Application for Rose CCS
Project Injection Wells No. 01, No. 02, and No. 03

SECTION 10 – ENVIRONMENTAL JUSTICE

Rose Carbon Capture and Storage Project
Jefferson County, Texas
ExxonMobil Low Carbon Solutions Onshore Storage LLC

February 2025

SECTION 10 – ENVIRONMENTAL JUSTICE¹

TABLE OF CONTENTS

10.0	Environmental Justice.....	5
10.1	EPA EJ Screening	8
10.1.1	Summary.....	8
10.1.2	Methodology	9
10.1.3	EJ Assessment and Analysis	11
10.2	EJ Communities of Concern	20
10.3	Preliminary EJ and Stakeholder Engagement.....	21
10.3.1	Stakeholder Engagement.....	21
10.3.2	Community Grievance Mechanism.....	24
10.3.3	Stakeholder Feedback	25
10.4	Next Steps	27

List of Tables

Claimed as PBI

List of Figures

Claimed as PBI

¹ Note: Applicant is including this analysis due to its commitment to, and the importance of, community engagement in the Class VI well permitting process, as well as existing federal guidance. Applicant reserves the right in the future to revise this analysis if interpretation or implementation of federal law or regulation should change.

Claimed as PBI

Appendix K – Environmental Justice

Claimed as PBI

-Page Intentionally Left Blank-

10.0 Environmental Justice²

On March 7, 2024, ExxonMobil Low Carbon Solutions Onshore Storage LLC (ExxonMobil) submitted a Class VI Permit Application (Application) to the U.S. Environmental Protection Agency (EPA) for the Rose Carbon Capture and Storage (CCS) Project (Project). Since that time, additional community engagement has been conducted and feedback received with regards to the Project. The purpose of this amendment is to incorporate the recently obtained data into the Environmental Justice (EJ) section of this Application to demonstrate compliance with regulatory requirements and to demonstrate that the relevant EPA guidance has been appropriately considered in developing this Application, including the August 2023 "Memorandum of Environmental Justice Guidance for UIC [Underground Injection Control] Class VI Permitting and Primacy" (Fox, 2023).

This EJ Screening Report (the Report) for the proposed Project is an initial desktop assessment of potential EJ-related concerns that could be raised by the local community in which the Project will be located and will continue to be refined throughout the life of the Project. The Report identifies community characteristics useful in guiding engagement through Project planning, permitting, construction, operation, and decommissioning.

ExxonMobil anticipates that Project development activities will be supportive of the environmental and socioeconomic needs of the communities in which the Project will operate. In addition, ExxonMobil has developed a Stakeholder Engagement Plan to facilitate meaningful community engagement with local leaders, residents, economic developers, environmental organizations, and others. Consistent with ExxonMobil's socioeconomic management principles (ExxonMobil, 2024)³, a stakeholder grievance/feedback process is described in Section 10.3.2 below, which has been developed that will allow stakeholders to have access to ExxonMobil throughout the Project lifecycle.

The Report includes the use of an initial "EJ Study Area" to assess the presence of communities that may be associated with potential EJ concerns. Although EPA guidance states that the Area of Review is normally used as the boundary to be investigated for EJ purposes. ExxonMobil is going beyond that requirement here in that the EJ Study Area comprises the area within a two-mile radius around the Project (Project Footprint), which includes wells to the west and pipelines to the east. The Project Footprint is the physical area that will be occupied by the Project operations facilities or disturbed by Project construction or operations activities.⁴ A radius of two miles was selected for the EJ Study Area because the bulk of construction and operation activities for the Project are expected to be concentrated within this area. The EJ Study Area includes  Census Block Groups (CBGs),⁵ which are located in Jefferson County (EPA, 2023a)

² ExxonMobil is including this analysis due to its commitment to, and the importance of, community engagement in the Class VI well permitting process, as well as existing federal guidance. Applicant reserves the right in the future to revise this analysis if interpretation or implementation of federal law or regulation should change.

³ <https://corporate.exxonmobil.com/sustainability-and-reports/sustainability/engaging-communities-and-our-supply-chain/managing-socioeconomic-impacts/community-engagement-and-grievance-management>

⁴ For the purpose of this Report, the Project Footprint does not include the existing roadways that will be used to transport Project construction materials or workers.

⁵ A CBG is the smallest geographic unit used by the U.S. Census Bureau to collect data for decennial census data. A CBG consists of Block Groups (BGs) within Census Tracts (CTs). Throughout this EJ Report, individual CBGs are referred to by an identifier in the form "CT XXX BG X."

CONFIDENTIAL BUSINESS INFORMATION

(Figure 10-1). Although a limited portion of [redacted] falls within a 2-mile radius of the Project Footprint, this CBG was not included based on the relatively small amount of the CBG within the 2-mile radius. As the Project is defined in further detail and community engagement continues, it is possible that additional CBGs may warrant assessment.

Claimed as PBI

10.1 EPA EJ Screening

10.1.1 Summary

This Report employs the use of U.S. Census and other data for early identification of potential Project-related impacts and opportunities associated with potential EJ concerns. The Claimed as PBI CBGs within the EJ Study Area demonstrate a range of socioeconomic characteristics. Based on an analysis of the data provided in this Report, the following are noted:

Claimed as PBI

⁶ For each CBG, each environmental indicator has its own EJ Index, which combines the demographic index (which averages low-income and people of color populations) with the respective environmental indicator percentile value for the CBG. For example, the EJ index for traffic for a given CBG is calculated as (traffic indicator percentile for the CBG) x (average of low-income population percentage and the people of color population percentage for CBG).

10.1.2 Methodology

The U.S. Environmental Protection Agency (EPA) defines EJ as the:

“[F]air treatment and meaningful involvement of all people regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies. This goal will be achieved when everyone enjoys:

- The same degree of protection from environmental and health hazards; and
- Equal access to the decision-making process to have a healthy environment in which to live, learn, and work.”

The EPA EJ guidance (EPA, 2016; EPA, 2022) does not prescribe a method for assessing potential EJ impacts. However, it does recommend that an appropriate methodology be adopted and applied. ExxonMobil has a corporate socioeconomic standards-driven⁷ process that assesses environmental, socioeconomic, and health considerations throughout a Project. As ExxonMobil’s understanding of the local environment evolves during the Project lifecycle, and, if warranted, the EJ assessment may be updated.

For this Report, the EPA’s EJScreen Tool Version 2.2 (EPA, 2023a) was used to assess demographic and environmental characteristics in areas crossed by or within the EJ Study Area (Figure 10-1). Use of the EJScreen Tool is intended to be a starting point in the identification of communities with potential EJ concerns. As discussed further in Section 10.1.2.4, EJ Indexes at or above the 80th percentile nationally were used as a starting point for identifying geographic areas that potentially warrant further consideration, analysis, or engagement with respect to potential EJ concerns.

10.1.2.1 Minority Populations

In accordance with the EPA’s EJ guidance (EPA, 2016; EPA, 2022), this EJ Report uses demographic and socioeconomic data to assess levels of minority⁸ population percentages present in the EJ Study Area and the broader Jefferson County. The U.S. Council on Environmental Quality (CEQ) states that “minority populations should be identified where either: (a) the minority population of the affected area exceeds 50% or (b) the minority population percentage of the affected area is *meaningfully greater* [emphasis added] than the minority population percentage in the general population or other appropriate unit of geographic analysis” (CEQ, 1997). The CEQ recommends using an “appropriate unit of geographic analysis” that does not “artificially dilute or inflate the affected minority population” (CEQ, 1997). While “meaningfully greater” is not explicitly defined in the CEQ’s guidance, federal guidelines suggest that 10% greater than the reference population is considered a reasonable threshold for

⁷ [Managing socioeconomic impacts | ExxonMobil](#)

⁸ “Minority” was initially defined by the Federal Interagency Working Group on Environmental Justice in an appendix to the 1997 CEQ EJ Guidance as “individuals who are members of the following population groups: American Indian or Alaskan Native; Asian or Pacific Islander; Black, not of Hispanic origin; or Hispanic” (CEQ, 1997).

“meaningfully greater” (EJ IWG and NEPA Committee, 2019). To identify minority populations for the CBGs in the EJ Study Area, Jefferson County was used as the reference population.

For this EJ Report, potential minority populations are identified as present in a CBG if it meets either of the following criteria:

- The percentage of minorities in the CBG is more than 50%; or
- The percentage of minorities in the CBG is at least 10% higher than that of Jefferson County.

10.1.2.2 Low-Income Populations

Utilizing EPA’s EJ guidance (EPA, 2016; and EPA, 2022), this EJ Report evaluated socioeconomic data to assess levels of low-income percentages of populations present in the EJ Study Area and the broader Jefferson County. Guidelines for identifying low-income populations vary among federal and state agencies. Low-income populations can be identified using either (1) the U.S. Census Bureau poverty thresholds, (2) local data sources on poverty, or (3) the U.S. Department of Health and Human Services poverty guidelines. Additionally, low-income communities can be identified by using a “meaningfully greater” analysis, the percentage of *individuals* below the poverty level, the percentage of *households* below the poverty level, and/or the percentage of *families with children* below the poverty level (EJ IWG and NEPA Committee, 2019). The National Environmental Policy Act uses the “meaningfully greater” analysis to identify low-income populations.

For this Report, potential low-income populations are identified as present in a CBG if it meets the following criterion:

- The percentage of households below the poverty level in the CBG is greater than that of Jefferson County.

10.1.2.3 Additional Socioeconomic Indicators

Additional socioeconomic indicators measured by the EJScreen Tool include unemployment rate, percentage of population that is limited English speaking, percentage of population with less than high school education, percentage of population under age 5, percentage of population over age 64, a Demographic Index,⁹ and a Supplemental Demographic Index.¹⁰ Values for each of these indicators are compared between Jefferson County and each of the CBGs.

⁹ The demographic index in EJScreen is a combination of percentage of low-income and percentage of minority, the 2 socioeconomic factors that were explicitly named in Executive Order 12898 on Environmental Justice. For each CBG, these two percentages are averaged together to derive the Demographic Index. The formula is as follows: demographic index = (% minority + % low-income) / 2.

¹⁰ The supplemental demographic index in EJScreen is a combination of five socioeconomic factors averaged together for each CBG. The supplemental demographic index can provide an additional perspective on potential community vulnerability and may be more relevant for use in certain situations. The formula is as follows: supplemental demographic index = (% low-income + % unemployed + % less than high school education + % limited English speaking + low life expectancy) / 5. For BGs where low life expectancy data is missing, the formula will average the other four factors.

10.1.2.4 EPA EJScreen Tool EJ Indexes

There are 13 EJ Indexes in the EJScreen Tool corresponding to 13 environmental indicators, each combined with demographic indicators. An EJ Index can be used to characterize CBGs in terms of the combination of their low-income and people of color¹¹ populations and a given environmental indicator for the CBG. To calculate a CBG's EJ Index for a given environmental indicator, EJScreen multiplies the CBG's associated environmental indicator percentile by the average percentages of low-income and people of color (i.e., the Demographic Index) in the CBG.

Technical documentation for EJScreen recommends the use of an initial filter to promote consistency and as a pragmatic first step when interpreting screening results. The EPA has identified the 80th percentile filter as that initial starting point (i.e., an area with any of the 13 EJ Indexes at or above the 80th percentile may warrant further review).

EJScreen reports present the EJ Index percentiles both nationally and statewide. The national percentiles are the focus of this Report based on EPA technical guidance documents (EPA, 2016; EPA, 2022). National and state percentiles can be found in Appendix K-1, which includes the full EJScreen Community Reports for Jefferson County and each of the CBGs. Tables 1 and 2 in Appendix K-2 present individual demographic and environmental indicators that have resulted in a particular percentile.

10.1.3 EJ Assessment and Analysis

10.1.3.1 EPA EJScreen EJ Indexes

Of the [REDACTED] Indexes at or above the 80th percentile nationally. EJ Indexes with one or more CBGs with rankings at or above the 80th percentile nationally include PM2.5, Ozone, Diesel PM, Air Toxics Cancer Risk, Air Toxics Respiratory HI, Toxic Releases to Air, Superfund Proximity, Risk Management Program Facility Proximity, Hazardous Waste Proximity and Wastewater Discharge. The most common EJ Indexes at or above the 80th percentile nationally in the EJ Study Area are Air Toxics Cancer Risk and Toxic Releases to Air, each present above the 80th percentile nationally in [REDACTED].

Table 10-1 summarizes the EJ Index national percentile rankings for Jefferson County and each of the CBGs in the EJ Study Area. Values at or above the 80th percentile nationally are shown in bold and the cells are shaded dark gray.

¹¹ In EJScreen, "low-income" is defined by the EPA as the percentage of a block group's population in households where the household income is less than or equal to twice the federal "poverty level." "People of color" are defined by the EPA as the percentage of individuals in a block group who list their racial status as a race other than white alone and/or list their ethnicity as Hispanic or Latino (i.e., all people other than non-Hispanic white-alone individuals, where the word "alone" in this case indicates that the person is of a single race, not multiracial) (EPA, 2022; EPA, 2023b).

Claimed as PBI

10.1.3.2 Demographic Indicators

This Report considers a subset of EJScreen demographic indicators for the CBGs in the EJ Study Area. The full EJScreen reports for each of the CBGs are provided in Appendix K-1. The state and national percentile rankings tables are provided in Appendix K-2. Table 10-2 summarizes the percentage values for demographic indicators for each CBG and for Jefferson County. Table 10-2 uses the combined “meaningfully greater” and 50% threshold methodologies to identify the CBGs that may warrant further evaluation on the basis of minority population percentages. For all other demographic indicators, Table 10-2 uses a direct comparison of the value for the CBG and that of Jefferson County. CBG values exceeding these comparison thresholds are shown in bold and the cell is shaded dark gray. **Claimed as PBI** CBGs have populations of people of color greater than 50%. Both **Claimed as PBI** and **Claimed as PBI** also have low-income populations higher than the Jefferson County reference population. The Demographic Index (an average of the percentage of low-income and percentage of people of color) is greater than that of Jefferson County percentage and above 50% in **Claimed as PBI** CBGs.

Claimed as PBI

10.1.3.3 Critical Service Gaps

EJScreen includes indicators for critical service gaps such as broadband internet subscription gaps, lack of health insurance,¹² housing burden, transportation access, and presence of food deserts.¹³ Descriptions of the indicators for these EJScreen layers are as follows:

- Broadband gaps refer to the percentage of households with a broadband internet subscription as reported in the Census Bureau's American Community Survey (ACS) five-year summary estimates (Figure 10-2).
- Lack of health insurance is the percentage of all persons without health insurance coverage as reported in the Census Bureau's ACS data (Figure 10-3).
- Housing burden is a percentile related to housing cost, which is the percentage of households that are both earning less than 80% of Housing and Urban Development's Area Median Family Income and are spending more than 30% of their income on housing costs (Climate and Economic Justice Screening Tool [CEJ, 2023]) (Figure 10-4).
- Transportation access is an average of four transportation-related indicator percentiles: transportation cost burden, national walkability index, percentage of households with no vehicle available, and mean commute time to work (Climate and Economic Justice Screening Tool) (Figure 10-5).
- Food desert tracts are those that are both low-income and "low-access," the latter of which is identified as tracts that are separated from affordable and nutritious foods by a distance of 1 mile for urban areas and 10 miles for rural areas, as reported by the U.S. Department of Agriculture (Figure 10-6).

Broadband internet subscription gaps at or above the 80th percentile occur within the portion of the EJ Study Area between Interstate 10 (I-10) and West Port Arthur Road. Lack of health insurance surpasses the 80th percentile for the entire portion of the Project Footprint from the eastern end of the Project Footprint near Central Gardens up until just east of I-10. Housing burden does not exceed the 80th percentile in the EJ Study Area. Transportation access burdens occur above the 80th percentile in only [REDACTED]

Claimed as PBI [REDACTED]

Figures 10-2 through 10-6 show the graphical data from the EJScreen Tool for each of the above critical services gaps.

¹² Percentage of all persons without Health Insurance Coverage as reported in the Census Bureau's ACS data.

¹³ Food desert tracts are low-income and low-access CTs with limited access to affordable and nutritious foods, measured at 1 mile distance for urban areas and 10 miles distance for rural areas, as reported by the U.S. Department of Agriculture.

Claimed as
PBI

Claimed as
PBI

Claimed as
PBI

Claimed as
PBI

Claimed as PBI

10.2 EJ Communities of Concern

The EJ assessment revealed a number of CBGs that are most likely to contain communities with potential EJ concerns based on the EJScreen environmental indices, applying EPA's recommended threshold of focusing on areas in the 80th percentile or higher. With respect to environmental indicators, CBGs CT 13.03 BG 2, CT 113.04 BG 3, and CT 9802 BG 1 are in the 80th percentile or higher on the most variables (each in the 80th percentile or higher for six or more environmental variables, and for four or more demographic variables at a regional or broader project level).

Claimed as PBI

Claimed as PBI

Claimed as PBI

10.3 Preliminary EJ and Stakeholder Engagement

While there are inherent risks in any type of development or operation, the Project seeks to avoid identified risks, mitigate remaining risks to acceptable levels, and to remedy the potential impacts. ExxonMobil uses core processes and internal frameworks to systematically identify, assess, manage, and monitor environmental and socioeconomic risks, opportunities and impacts throughout the lifecycle of the Project. Community feedback, scientific understanding, and other due-diligence information is considered to enable safer and responsible operations for the Project. ExxonMobil periodically update these assessments to reflect changes to operational complexity or socioeconomic sensitivities and amend management plans, as needed.

10.3.1 Stakeholder Engagement

The Project seeks to work collaboratively and transparently with local communities to promote positive, long-term relationships. ExxonMobil is consulting with local groups and individuals regularly and seek to have our stakeholders represented as community concerns are discussed and decisions are made. Our engagement process is continually tailored to be locally and culturally appropriate and provide accessible, inclusive, and effective channels for exchanging information and proactively identifying issues or concerns.

ExxonMobil has developed an initial Stakeholder Engagement Plan, which guides the management of the socioeconomic dynamics that may impact—or be impacted by—the Project. Considerations related to potential communities warranting further assessment from an EJ perspective, local economic development, workforce development, and grievances are routinely measured, assessed, and used to inform stakeholder engagement and impact mitigation strategies throughout the Project's lifecycle. Further detail on the project's Community Grievance Mechanism (CGM) is provided in Section 10.3.2.

ExxonMobil has been working to engage and inform local community individuals, community leaders, and elected officials on topics related to CCS and the overall Project. Table 10-3 provides a non-exhaustive summary of the Project's community engagement activities conducted to-date, which includes formats such as, but not limited to, community gatherings, individual meetings, and open houses. In addition to the listed community engagements, ongoing engagements are being conducted with elected officials, and other relevant stakeholders to provide project updates. Community engagement will be continuous throughout the lifecycle of the project. As involvement with the local community grows, the Stakeholder Engagement Plan will continue to be refreshed.

Claimed as PBI

Claimed as
PBI

Claimed as PBI



Claimed as PBI

10.3.2 Community Grievance Mechanism

ExxonMobil has developed a CGM, which receives complaints, concerns, issues, requests, or other feedback (collectively termed “input” herein) related to the Project and allows for response to this input in a consistent, transparent, and timely manner. The CGM will be active throughout the lifecycle of the project. The objectives of the CGM are to:

- Provide an accessible mechanism for stakeholders to provide input to the Project team;
- Facilitate the Project’s processing of stakeholder input such that the input is acknowledged, tracked, and addressed in a timely manner respecting confidentiality;
- Continuously improve Project performance based on consideration of stakeholder input provided through the CGM; and
- Demonstrate commitment to meaningful stakeholder engagement and respect for stakeholder input.

The Project CGM is aligned with International Petroleum Industry Environmental Conservation Association best practices, as shown in Figure 10-7.

Claimed as PBI

The CGM is structured so that stakeholders may submit input in multiple ways. A CGM log is being used to record all engagements with stakeholders and all input received from stakeholders. This allows for analysis of trends in stakeholder interest and concern—which can help to design further engagement programs and activities—and tracking of Project responses to stakeholder input.

10.3.3 Stakeholder Feedback

Stakeholder feedback is being received through the CGM, initial field work for the development of the Project Local Economic Development Plan, and continuous engagement. [REDACTED]

[REDACTED]

Claimed as PBI

[REDACTED]

[REDACTED] his section highlights some common concerns of stakeholders in response to the Project and how ExxonMobil is responding accordingly to the feedback provided.

Claimed as PBI

10.3.3.1 Safety and Emergency Response

Section 146.94 of the regulations provides for an emergency and remedial response plan to describe the actions to be taken to address movement of the injection or formation fluids that may cause an endangerment to an Underground Source of Drinking Water (USDW).

Emergency response concerns have been shared by the community during the engagements and field work conducted to date. Emergency Service Districts (ESD) rely on volunteers; however, this system falters when volunteers do not appear during when they are needed.

Potential causes include conflicts with commitments to full-time jobs to support their families or other demands that prevent them from being available. [REDACTED]

[REDACTED]

Claimed as

PBI

[REDACTED]

10.3.3.2 Community Infrastructure

Based on feedback received and fieldwork conducted to date, the community is looking for investment opportunities to improve quality of life. Items cited included inadequate facilities and infrastructure to address prevalent health issues, food insecurity among seniors and youth, broadband access gaps, support needed for improvements/connections to sewer, natural gas, and development of recreational parks. [REDACTED]

Claimed as PBI [REDACTED]

10.3.3.3 Format for Engagements

Engagement formats should be tailored to respective communities and audiences. [REDACTED]

Claimed as PBI [REDACTED]

10.3.3.4 Noise

Claimed as PBI [REDACTED]

10.3.3.5 Lease Agreements

Claimed as PBI [REDACTED]

10.4 Next Steps

The EJ analysis and assessment for the Project will continue to be refined and updated throughout the lifecycle of the same as appropriate. As highlighted in Appendix K-3, activities are underway to address specific community feedback. As next steps the following project activities are being planned:

- Continue to gather feedback via CGM and community engagements;
- Ongoing response to community concerns and grievances;
- Continued refinement of management and mitigation plans based on the community feedback; and

[REDACTED]
[REDACTED]
Claimed as PBI
[REDACTED]
[REDACTED]

Appendix A Project Maps

Appendix B Site Characterization Files

-Page Intentionally Left Blank-

Appendix B Site Characterization Figures

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

-Page Intentionally Left Blank-

Appendix B.1 Claimed as PBI **Core Field Analyses**

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Appendix B.2 Claimed as PBI **Laboratory Analyses**

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Appendix B.3 Claimed as PBI **njectivity Test Report**

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Appendix B.4 Geochemical Model Tables

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Appendix B.5 Conventional Core Fracture Evaluation and Potential USDW Impact Assessment

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Figures

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

-Page Intentionally Left Blank-

Appendix C

Claimed as PBI

Claimed as PBI

CONFIDENTIAL BUSINESS INFORMATION
FOR THE NEXT 94 PAGES

Claimed
as PBI

Claimed as PBI

Claimed as PBI

Appendix C-4

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Appendix D Well Construction Schematics and Procedures

-Page Intentionally Left Blank-

Appendix D.1: Well Construction Design and Completion

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

-Page Intentionally Left Blank

Appendix D.2

Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

-Page Intentionally Left Blank-

Appendix D.3: Drilling and Completion Prognosis for Injection Wells

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI



Order round the world for the first time. The first time a round the world race. The first time a round the world race. The first time a round the world race.

Order round the world for the first time. The first time a round the world race. The first time a round the world race. The first time a round the world race.

Order round the world for the first time. The first time a round the world race. The first time a round the world race. The first time a round the world race.

Order round the world for the first time. The first time a round the world race. The first time a round the world race. The first time a round the world race.

Order round the world for the first time. The first time a round the world race. The first time a round the world race. The first time a round the world race.

February 5

Order round the world for the first time. The first time a round the world race. The first time a round the world race. The first time a round the world race.

[illegible]

5

☐☐ ☐☐ ☒☐ ☒☐ ☒☐ ☒☐ ☐ ☐☐ ☐

rd

S **d** **r** **S**

Overview of ExxonMobil's Operations Control System

☐ 5 ☐ re ☐

5 Ba

5 Reference

5 e e e

□55 □□□ arab □y

Standardiser

D **M** **S** s d s

[illegible]

u rea M r Da

[illegible]

u e e e r a e Da a

5 u r u d a e r M r D a a

5 D M r

5 Fr a er Bear e b e

a e u dy r a d r u d a er a e

R **r** **s**

9

5

Claimed as PBI

9

ae eay eBa

9

edeeaaeraraReerereead

[illegible]

de me a re e u a y a ura e r ocedure a a e
da a e a d e re ure e de ed e e a d M r a ab e
r de a u ary ea e a d r a y e e a d M r a a d
e a a ed ea ure de r bed e e ud e ur e e da a r ea ure e e
e e d da a a u a d e u e rd ary ab ra ry r a ay a a r r a e

Claimed as PBI

□ r □ u □ d □ a □ e □ r □ □ □ □ r □ □ □ a □ d □ a □ □ □ □ □ □ □ □ u □ b □ e □ □ □ □ □ □ □ □ e □ □ a □ □ □ □ u □ r □ e □ □ □ □ □ □ a □ r □ a □ b □ y □ □ u □ □ a □ □ □

- [illegible]

[illegible]

The laboratory's test methodology and within established detection limits. Laboratory equipment calibration and maintenance are described by the individual laboratory's analytical quality assurance manual. Following laboratory selection, the laboratory's analytical quality assurance manual must be reviewed by the laboratory's quality assurance manager before being used. The laboratory's quality assurance manual must be reviewed by the laboratory's quality assurance manager before being used.

Claimed as PBI

□

–□a□e□□□e□□□□a□y□□e□□Ba□□–□

Claimed as PBI

Claimed as PBI

Receivable Resources

Receivable data are derived from the receivable data entered into the system by the receivable department. Receivable data are entered into the system by the receivable department and are used to calculate the receivable balance.

Claimed as PBI

The receivable data are derived from the receivable data entered into the system by the receivable department and are used to calculate the receivable balance. The receivable data are entered into the system by the receivable department and are used to calculate the receivable balance.

Receivable Resources

The receivable data are derived from the receivable data entered into the system by the receivable department and are used to calculate the receivable balance. The receivable data are entered into the system by the receivable department and are used to calculate the receivable balance. The receivable data are entered into the system by the receivable department and are used to calculate the receivable balance.

Claimed as PBI

Receivable Resources

Data are derived from the receivable data entered into the system by the receivable department and are used to calculate the receivable balance. The receivable data are entered into the system by the receivable department and are used to calculate the receivable balance. The receivable data are entered into the system by the receivable department and are used to calculate the receivable balance.

E.6 Standards for Calibration of Instrument and Equipment

The standards for calibration of instrument and equipment are derived from the standards for calibration of instrument and equipment. The standards for calibration of instrument and equipment are derived from the standards for calibration of instrument and equipment. The standards for calibration of instrument and equipment are derived from the standards for calibration of instrument and equipment.

The standards for calibration of instrument and equipment are derived from the standards for calibration of instrument and equipment. The standards for calibration of instrument and equipment are derived from the standards for calibration of instrument and equipment. The standards for calibration of instrument and equipment are derived from the standards for calibration of instrument and equipment.

E.7 Data Management System and Acquisition

Data management system and acquisition are the processes of collecting, storing, and managing data. Data management systems are designed to collect, store, and manage data in a way that is efficient and effective. Data acquisition is the process of collecting data from a source and storing it in a database. Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database. Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database.

Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database. Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database. Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database. Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database.

The data management system and acquisition are the processes of collecting, storing, and managing data.

1. Data Management System and Acquisition

Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database. Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database. Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database. Data management systems are used to manage data in a way that is efficient and effective. Data acquisition is used to collect data from a source and store it in a database.

Claimed as PBI

Claimed as PBI

Source Material Document

able to reproduce the source material data and any other information that may be used to create the same or a similar document. The source material is a document that is used to create the same or a similar document. The source material is a document that is used to create the same or a similar document.

Claimed as PBI

It is the policy of the company to protect the confidentiality of the source material. The source material is a document that is used to create the same or a similar document. The source material is a document that is used to create the same or a similar document.

Claimed as PBI

The samples will be obtained at a sample port on the Project's central pad and analyzed in the laboratory. The data generated will be available to the operator and the CO2 pipeline and the sequestration field's distribution system. The data will be used to determine the ability to store CO2 in the reservoir and to determine the amount of CO2 that can be stored in the reservoir.

Claimed as PBI

The data will be used to determine the ability to store CO2 in the reservoir and to determine the amount of CO2 that can be stored in the reservoir. The quality control requirements by the laboratory will be aligned with the laboratory's certification process and will include the use of a laboratory standard and a laboratory standard deviation. The data will be used to determine the ability to store CO2 in the reservoir and to determine the amount of CO2 that can be stored in the reservoir.

Summary of the Data

The data will be used to determine the ability to store CO2 in the reservoir and to determine the amount of CO2 that can be stored in the reservoir. The data will be used to determine the ability to store CO2 in the reservoir and to determine the amount of CO2 that can be stored in the reservoir. The data will be used to determine the ability to store CO2 in the reservoir and to determine the amount of CO2 that can be stored in the reservoir.

s r r D

[illegible][illegible]

require the FR to include quarterly the a a e
e era d e d a a e a a e year y e e ab r a r y
a b r a e r e e r b e u e r e r r e r d e e r u a r e r r e r
e e

Claimed as
PBI

Claimed as PBI

[illegible]

a e d e e a a e r a a a e a a b e r e r a e e r a t u r e

Claimed as PBI

□ □ e □ □ □ r □ □ □ r □ □ □ □ e a b □ r a □ □ r y □ □

e e a e e r e e e a e a a a e d a a a a e u b e r a r e e
 e u e u a b e r e r e r e a b e d e a e e r e r a e e u e a d
 d e r a u e u a e a a e d r e d e a d r e r a
 e u e a e a b e r r u a e a r e a a a e d y a y
 e a r a e d r e e a b r a

[illegible]

Data are recorded by the data day
due to the error due to the
and the error due to the
the error due to the
the error due to the
the error due to the
the error due to the
the error due to the

Claimed as PBI

[illegible]

☐ e ☐ d ☐ du ☐ a ☐ e ☐ a ☐ er ☐ b ☐ e ☐ a ☐ ed ☐ a ☐ er ☐ a ☐ er ☐ a ☐ e ☐ r

☐ e ☐ a ☐ e ☐ a ☐ b ☐ e ☐ a ☐ ed ☐ e ☐ e ☐ a ☐ a ☐ er ☐ a ☐ a ☐ e ☐ a ☐ ab ☐ e

☐ re ☐ er ☐ a ☐ e ☐ era ure

Claimed as PBI

5 Fr a er Bear e b e

[illegible]

Claimed as PBI

Claimed as PBI

Claimed as PBI

Information may be submitted and distributed to a person or persons in a confidential manner, and may be submitted and distributed to a person or persons in a confidential manner.

Claimed as PBI

E.8 Data Validation and Usability

Data may be submitted and distributed to a person or persons in a confidential manner, and may be submitted and distributed to a person or persons in a confidential manner.

Referred to as a confidential matter, and may be submitted and distributed to a person or persons in a confidential manner.

Referred to as a confidential matter, and may be submitted and distributed to a person or persons in a confidential manner.

Referred to as a confidential matter, and may be submitted and distributed to a person or persons in a confidential manner.

Referred to as a confidential matter, and may be submitted and distributed to a person or persons in a confidential manner.

5. Referred to as a confidential matter, and may be submitted and distributed to a person or persons in a confidential manner.

Referred to as a confidential matter, and may be submitted and distributed to a person or persons in a confidential manner.

Referred to as a confidential matter, and may be submitted and distributed to a person or persons in a confidential manner.

Receber a educação requerida por lei, em um prazo determinado, para o acesso a uma determinada unidade de ensino, a fim de garantir a qualidade da educação e a formação adequada dos alunos.

Reeuryreudaeayearaeedye
rduaryemdbadaaadeuadema
urraereeraadarearredeuadeMMDeu

Re-evaluate array read and write efficiency and data quality
a-e-e-e-e

e da a u a y i d d a r r e a u r a y r e r e e a m e e e e e
 arab y a d e y a a e d y e d d a m b e r e e d a d a
 a e e a d e r e a r d e u a b y e d a D a a a d a a y u d e r e r e
 a d e a u a u e d a a a r a e r u d e u e a u r e e a e
 d e a d r e u u a e d d u a e r b a a r e a e
 e r u e d a a a e b e e e e d a d a e d u a e d e r i b e d e
 e d u d a e a y b e u e d e a e e a r a a d r e d e d a a

The following table shows the results of the analysis of the data collected from the survey. The table is divided into two main sections: the first section shows the results of the analysis of the data collected from the survey, and the second section shows the results of the analysis of the data collected from the survey.

E.9 Self-Assessment of QASP

☐ e uauyye de rbed ☐ ☐ ☐ ☐ ☐ ☐ ☐ be a e ed ☐ redu e ☐ ☐ ☐ e a ☐ r
☐ ue ☐ ☐ abe da a be ued ☐ ☐ ☐ ☐ e de ☐ ☐ ☐ ra ☐ ☐ ☐ re uary ☐ ☐ ☐ a e ☐ ☐ ☐ ☐ e ☐ ☐
☐ er a a e ☐ e ☐ ☐ ay ☐ ☐ ude ☐ ☐ ☐ ☐ ☐

- [illegible]

M b ay ra e e a e du e a d er r er
a e a u ed e e a d M r a a r a a a er da
bere ber du er er a a e e a da a a u a ed

[illegible]

Appendix F Testing and Monitoring

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Appendix G FEMA Maps and Infrastructure

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Appendix H: Plugging Schematics and Procedures

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

-Page Intentionally Left Blank-

Appendix I Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Appendix J Financial Assurance

-Page Intentionally Left Blank-

Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

-Page Intentionally Left Blank-

A [REDACTED] Claimed as PBI

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Appendix K Environmental Justice

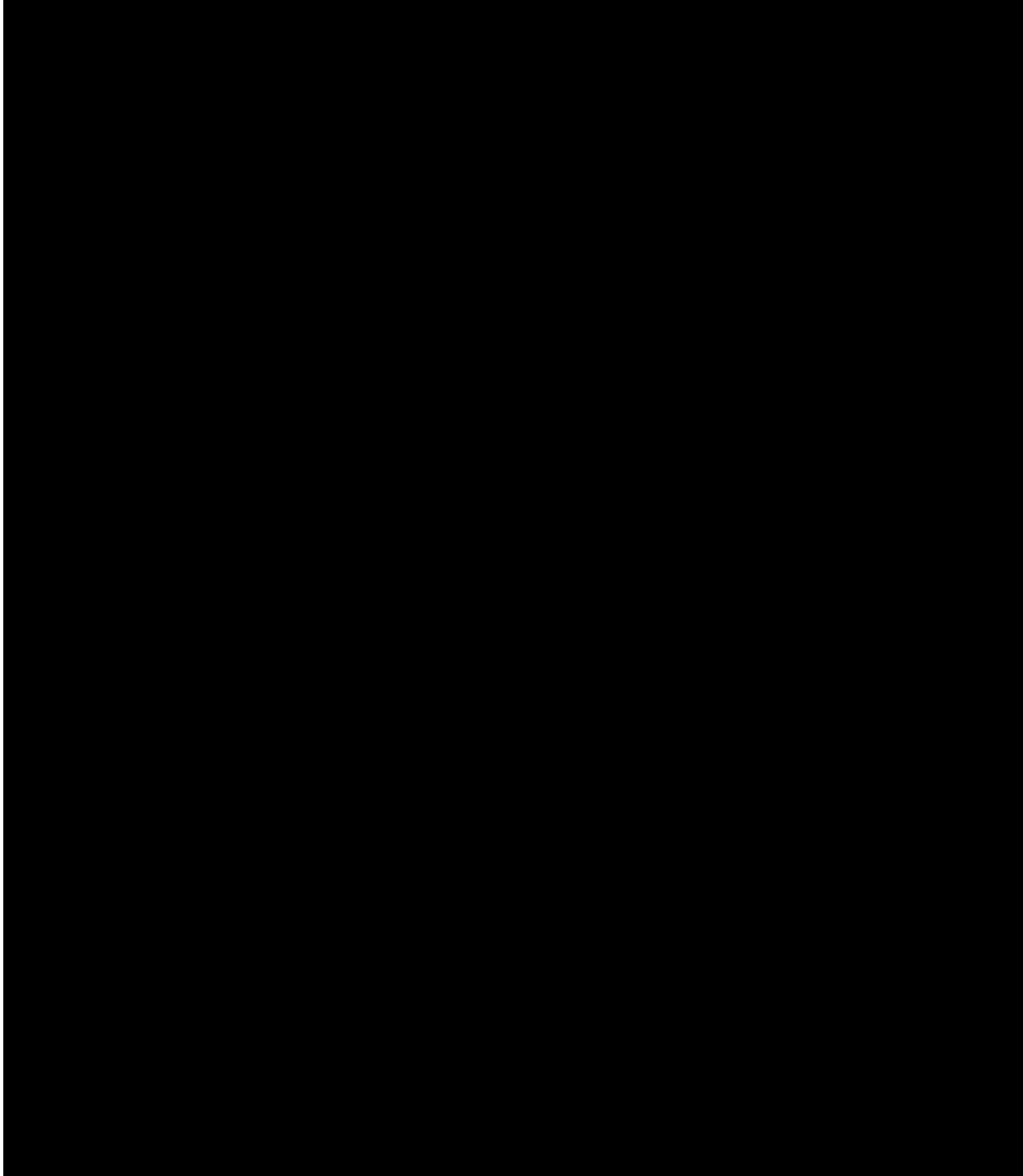
-Page Intentionally Left Blank-

Claimed as PBI

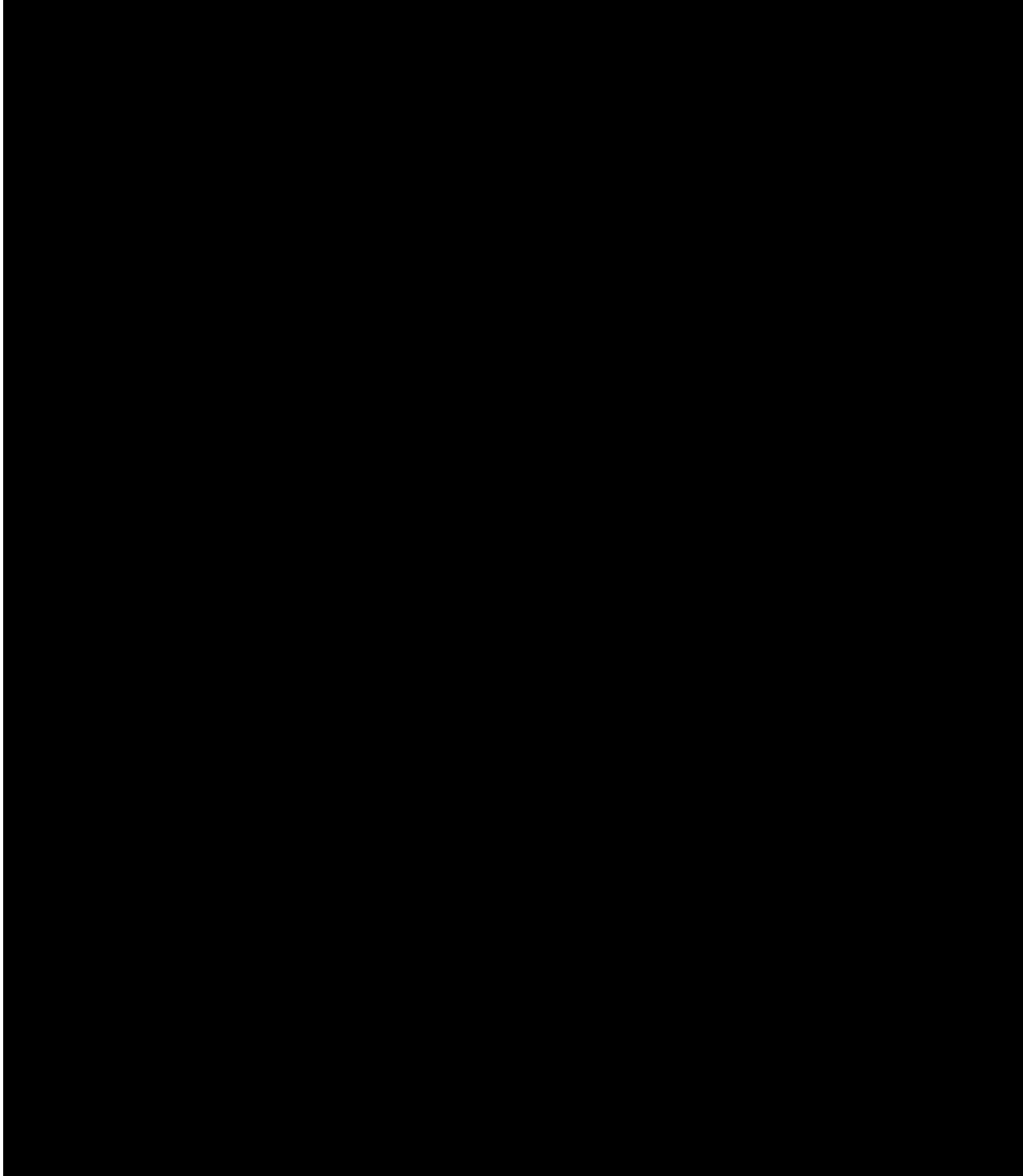
-Page Intentionally Left Blank-

Claimed as PBI

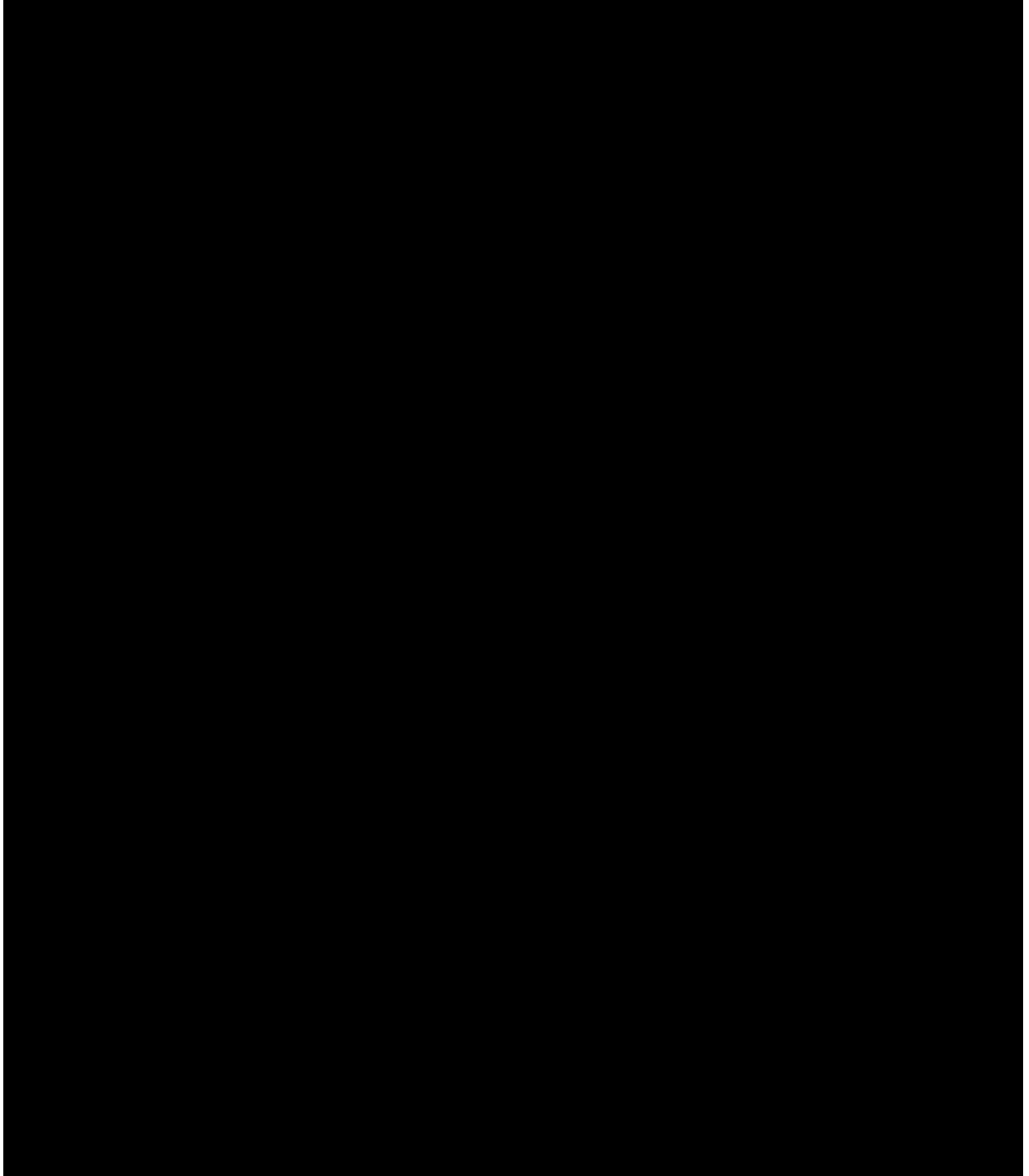
Claimed as PBI



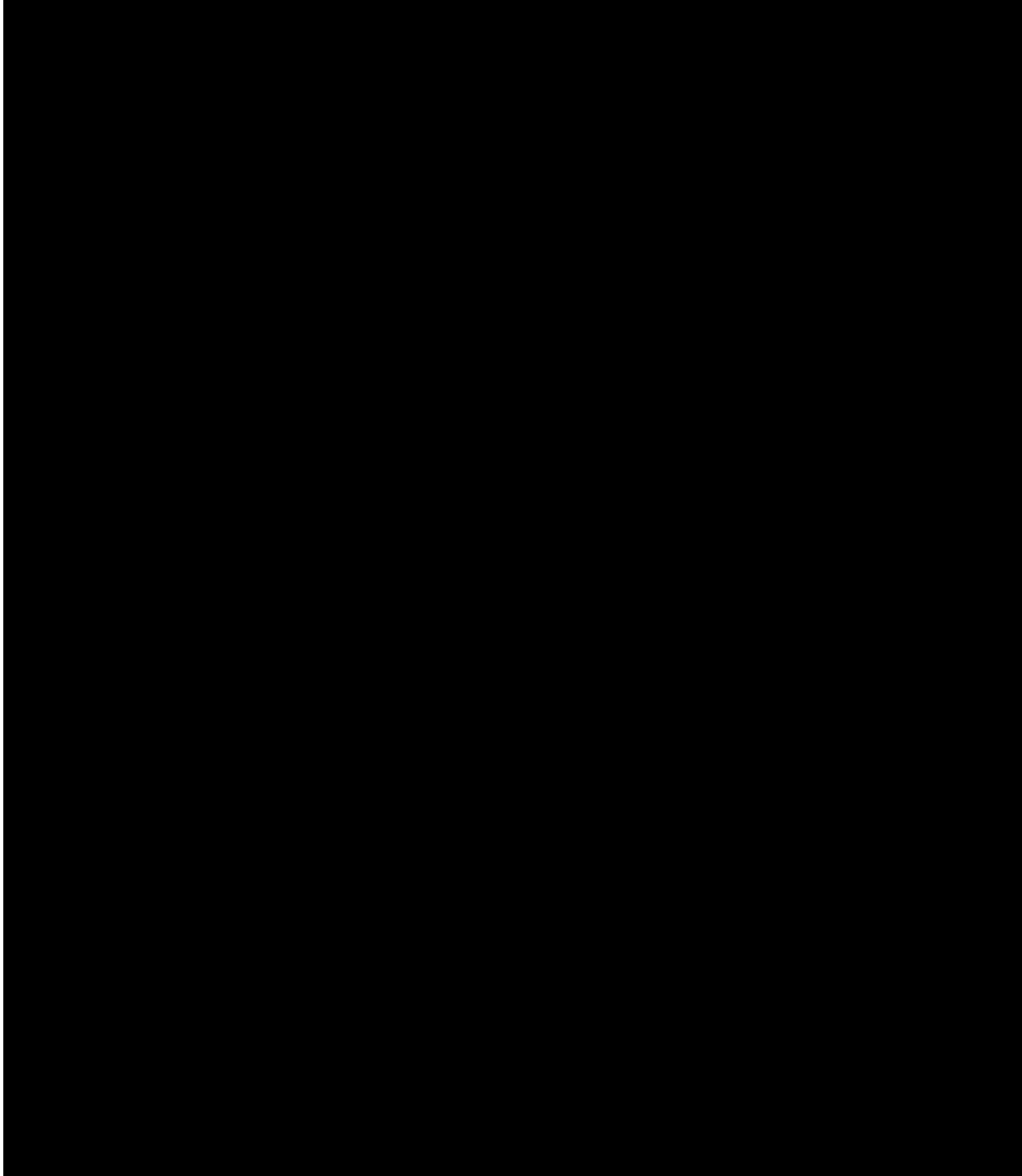
Claimed as PBI



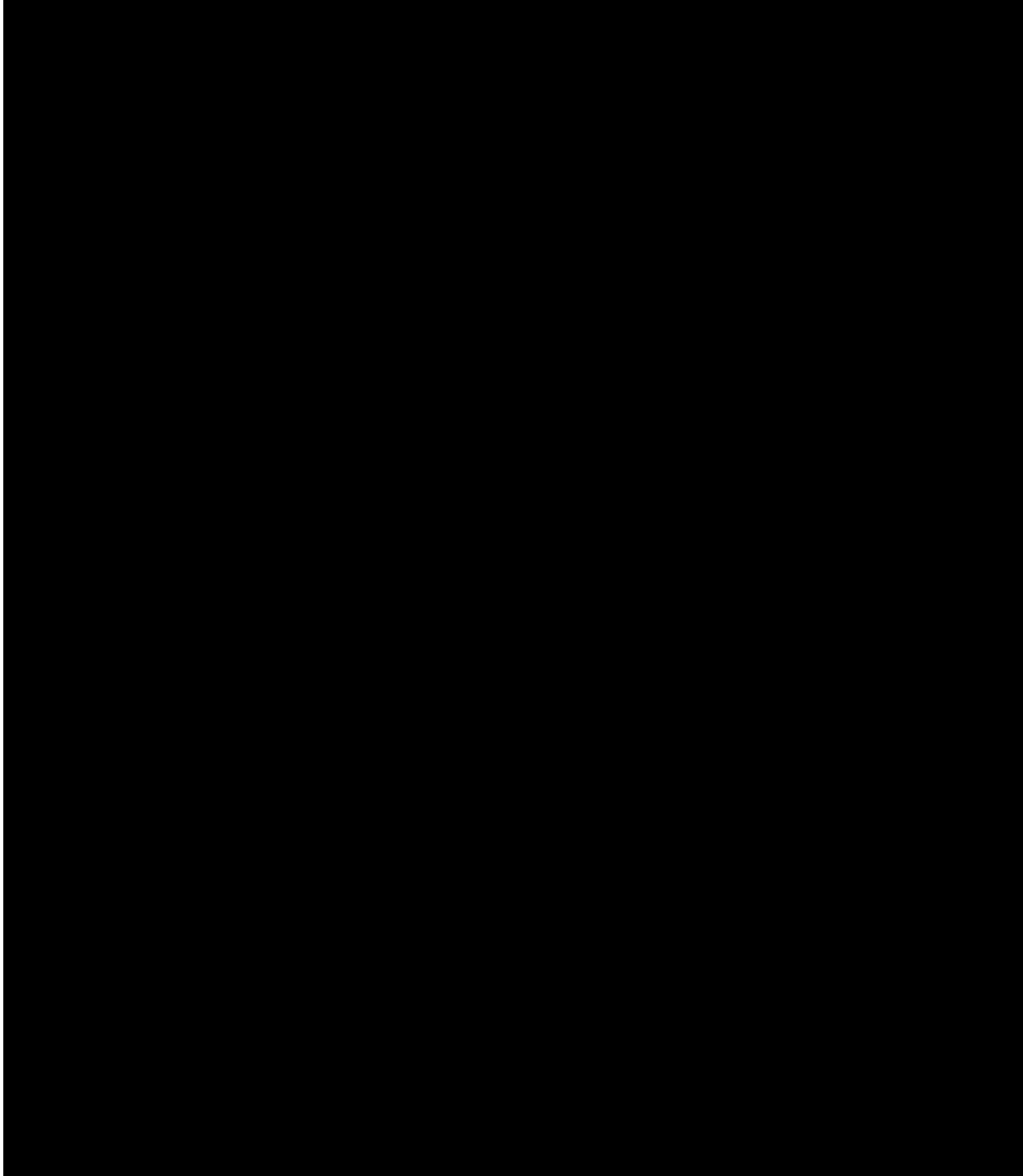
Claimed as PBI



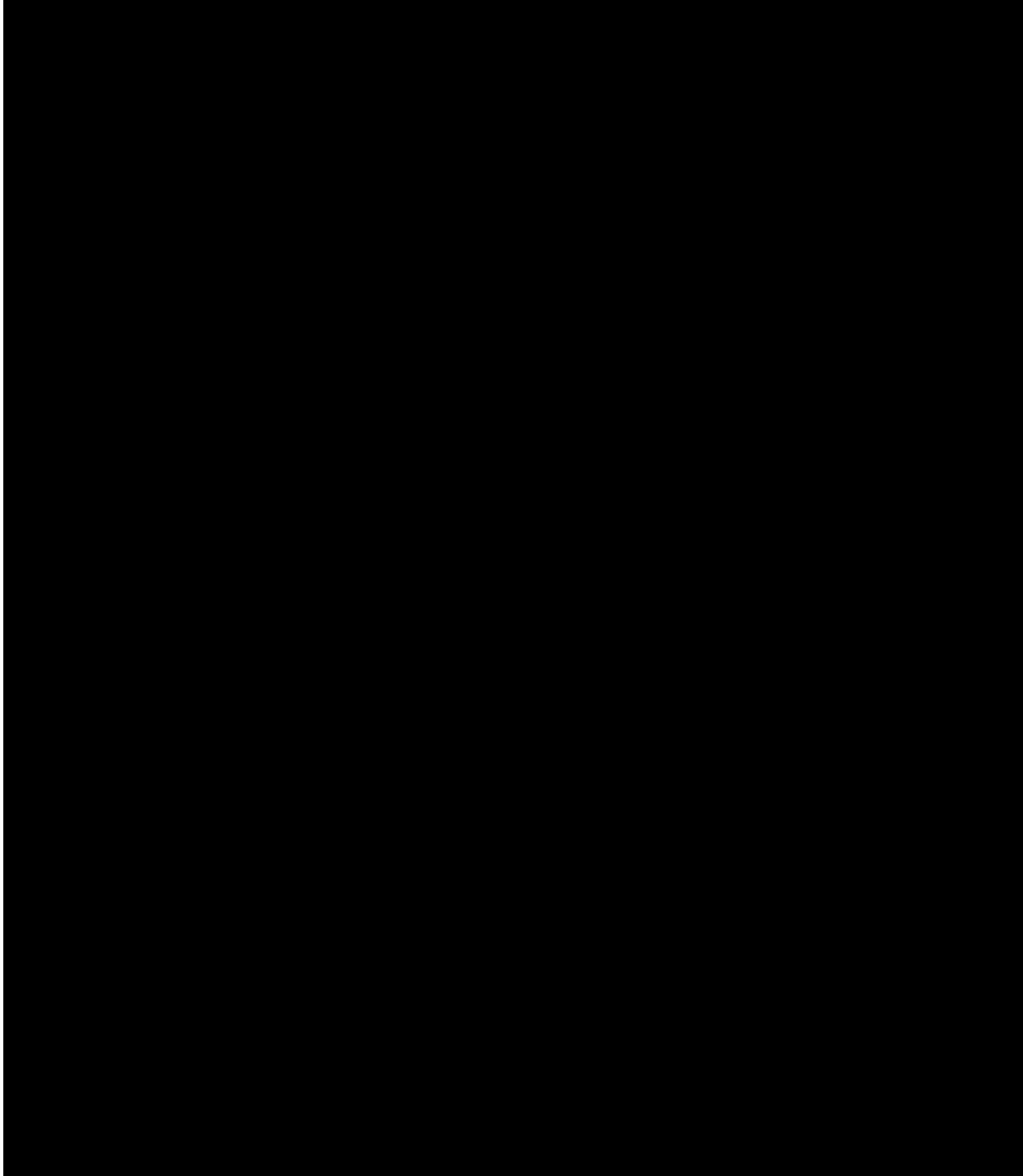
Claimed as PBI



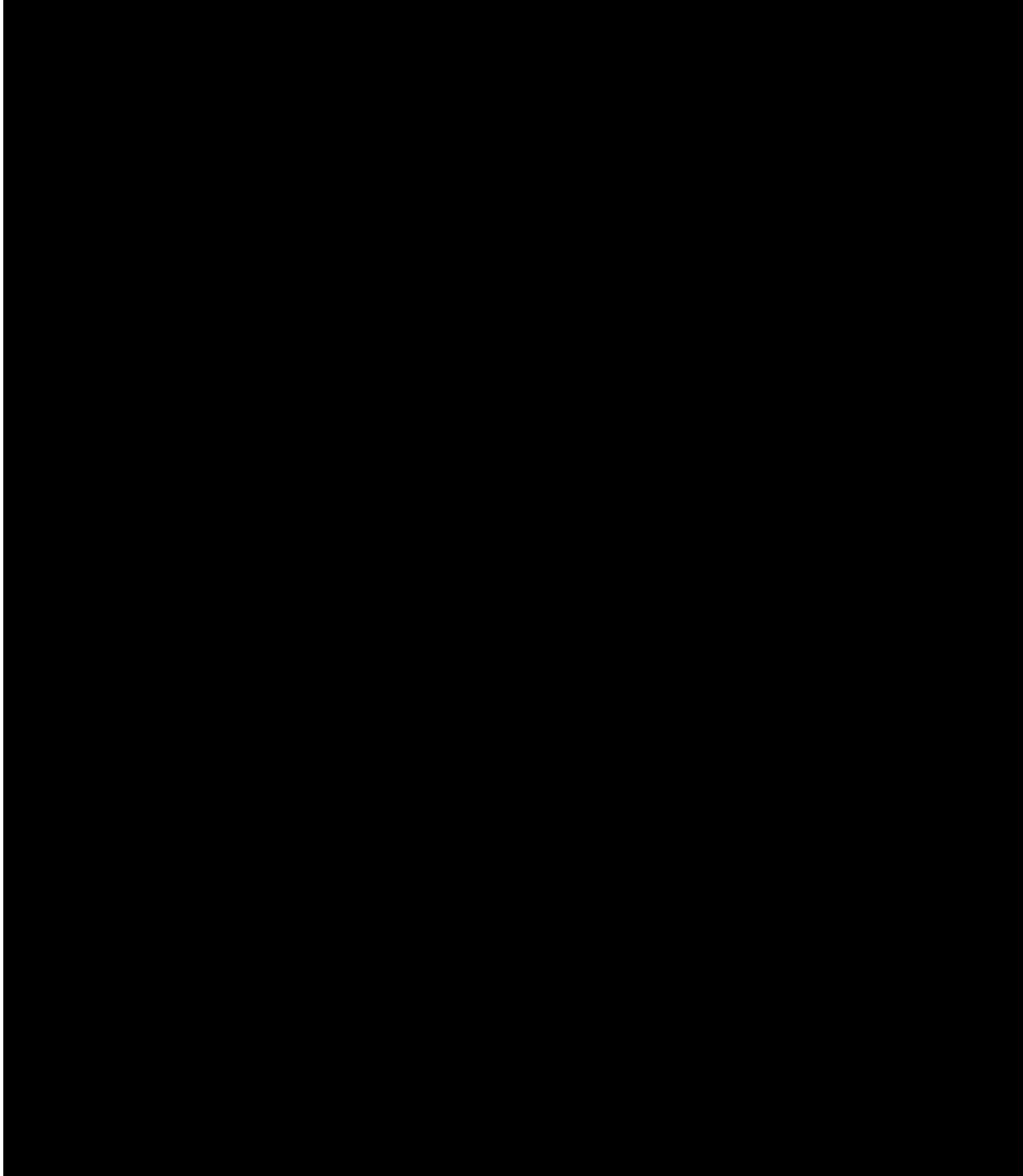
Claimed as PBI



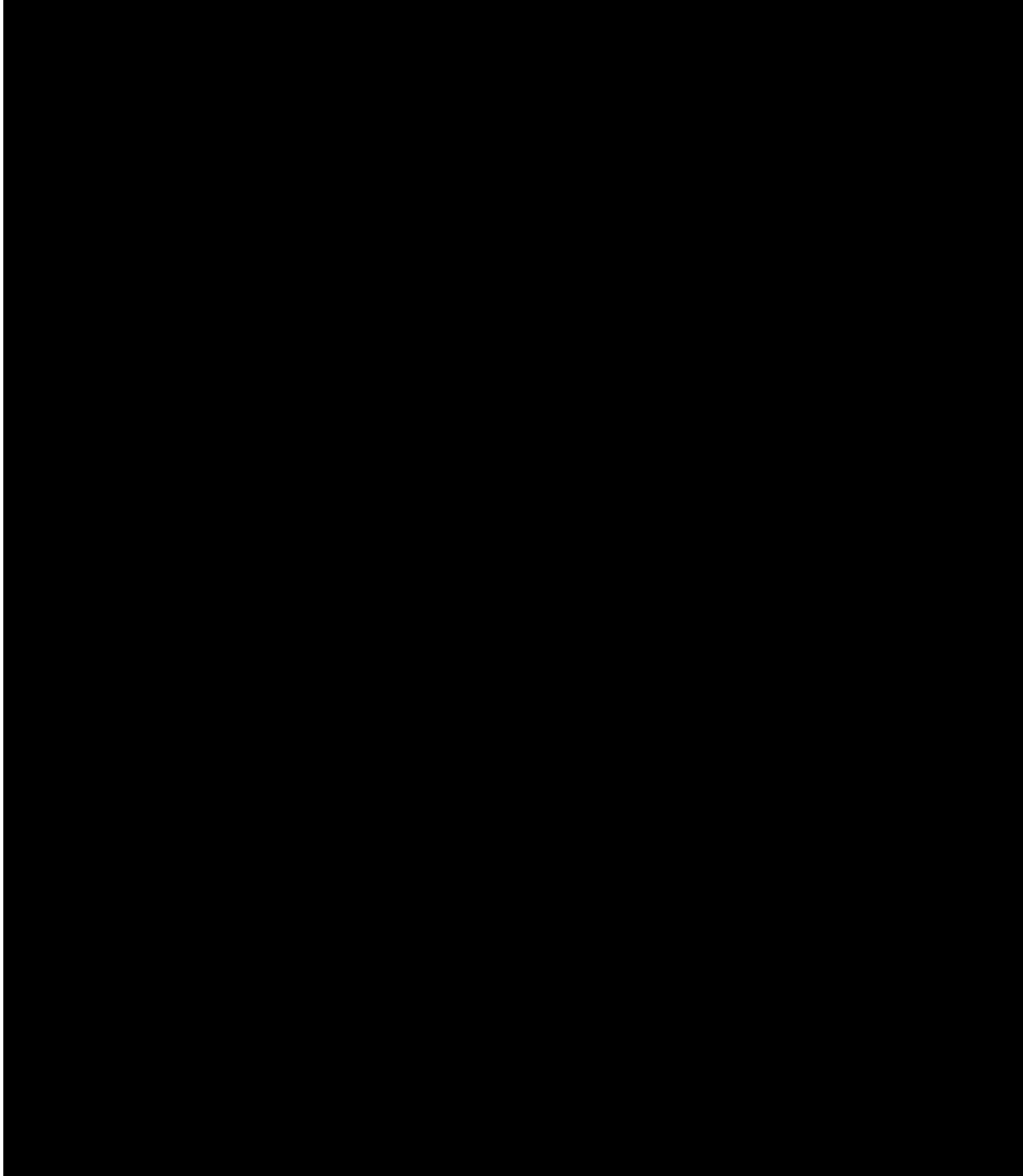
Claimed as PBI



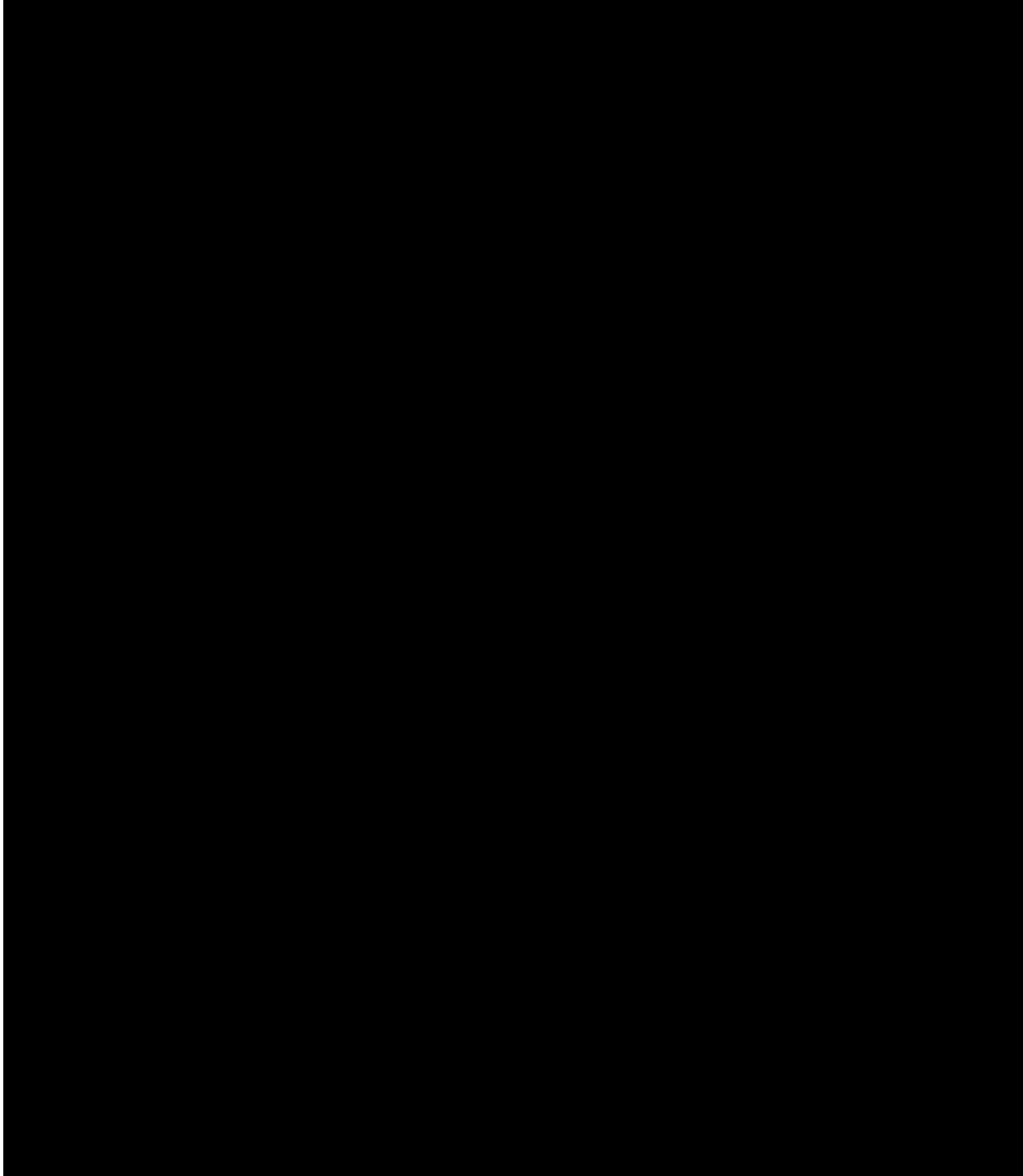
Claimed as PBI



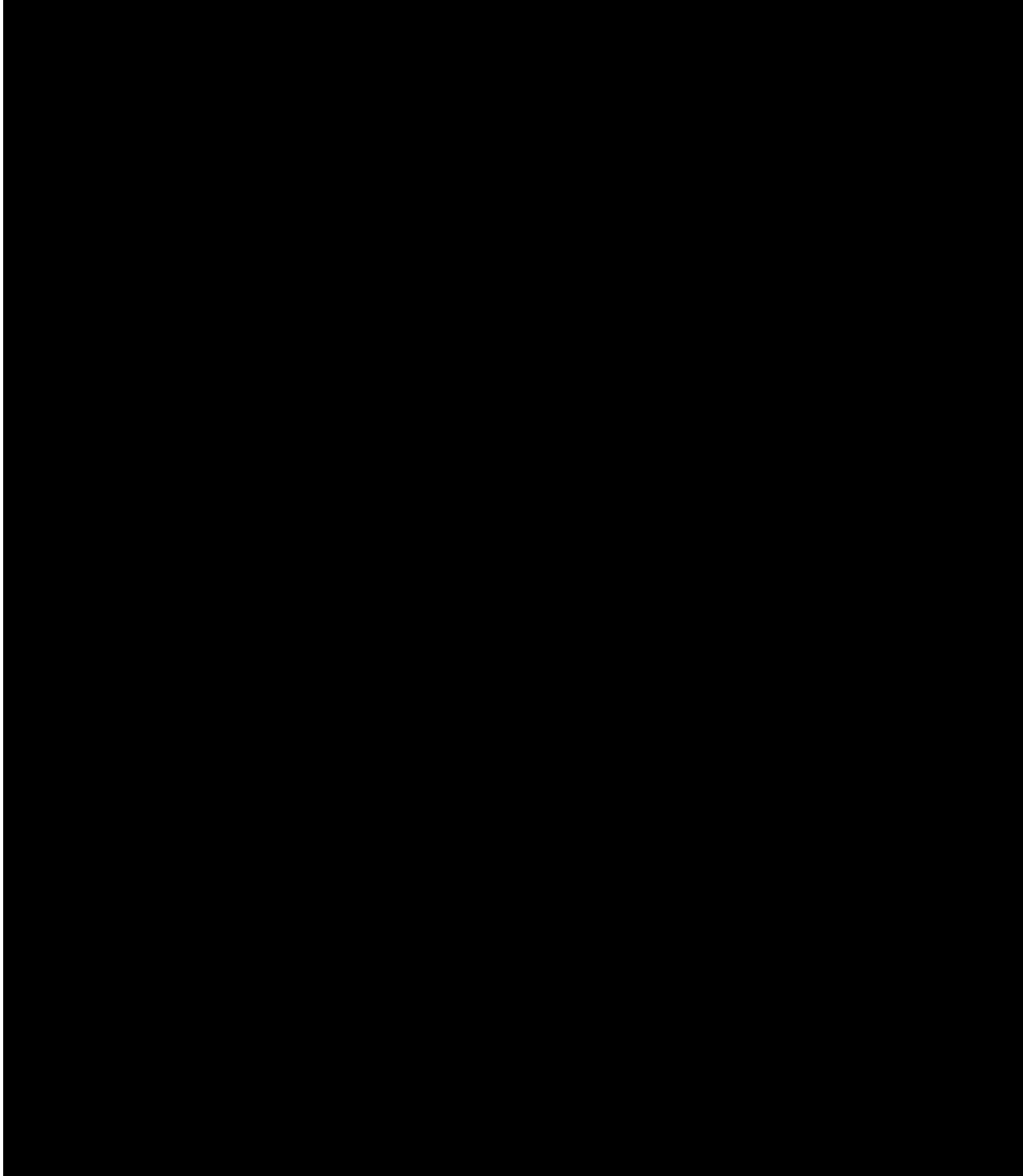
Claimed as PBI



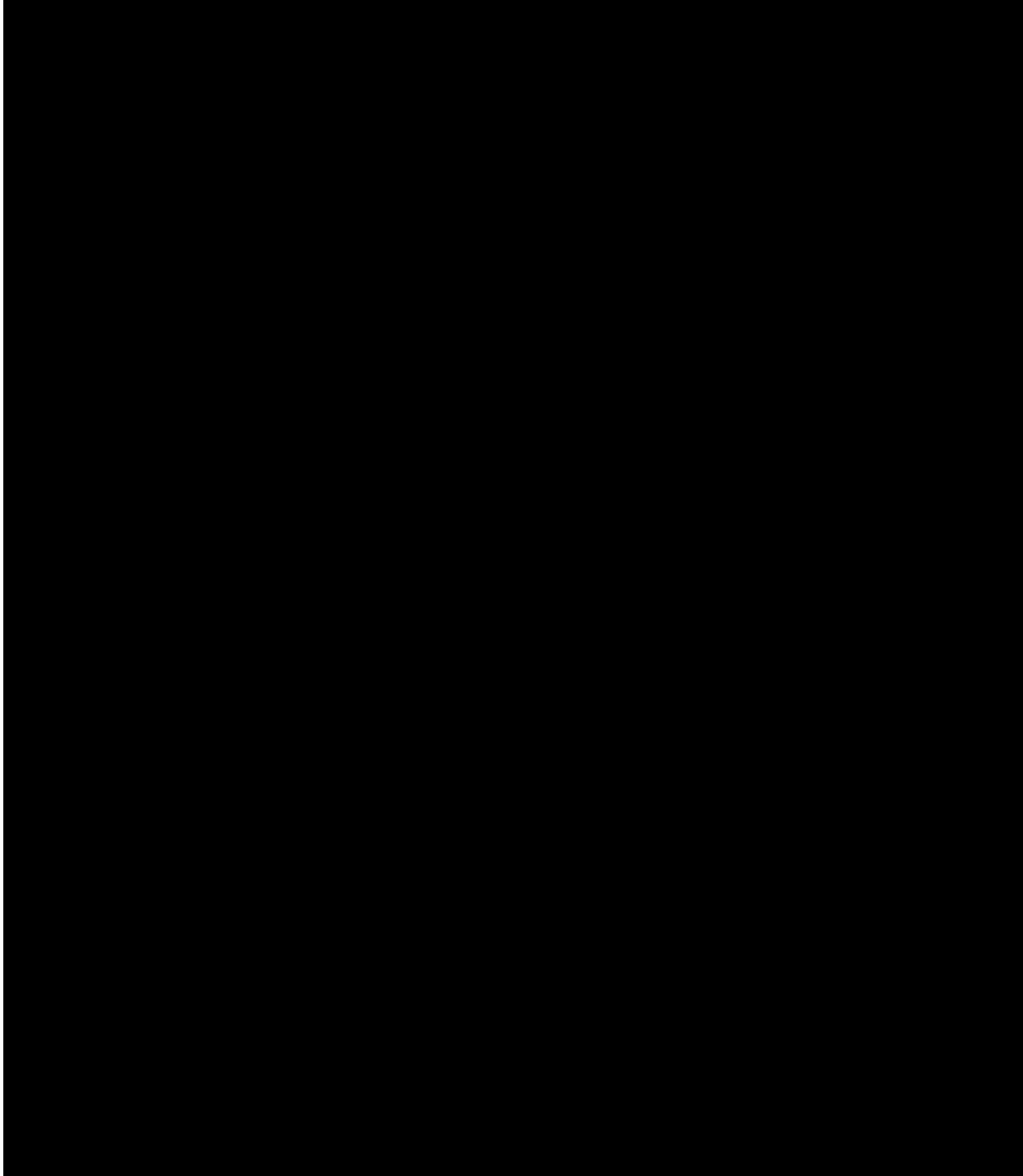
Claimed as PBI



Claimed as PBI

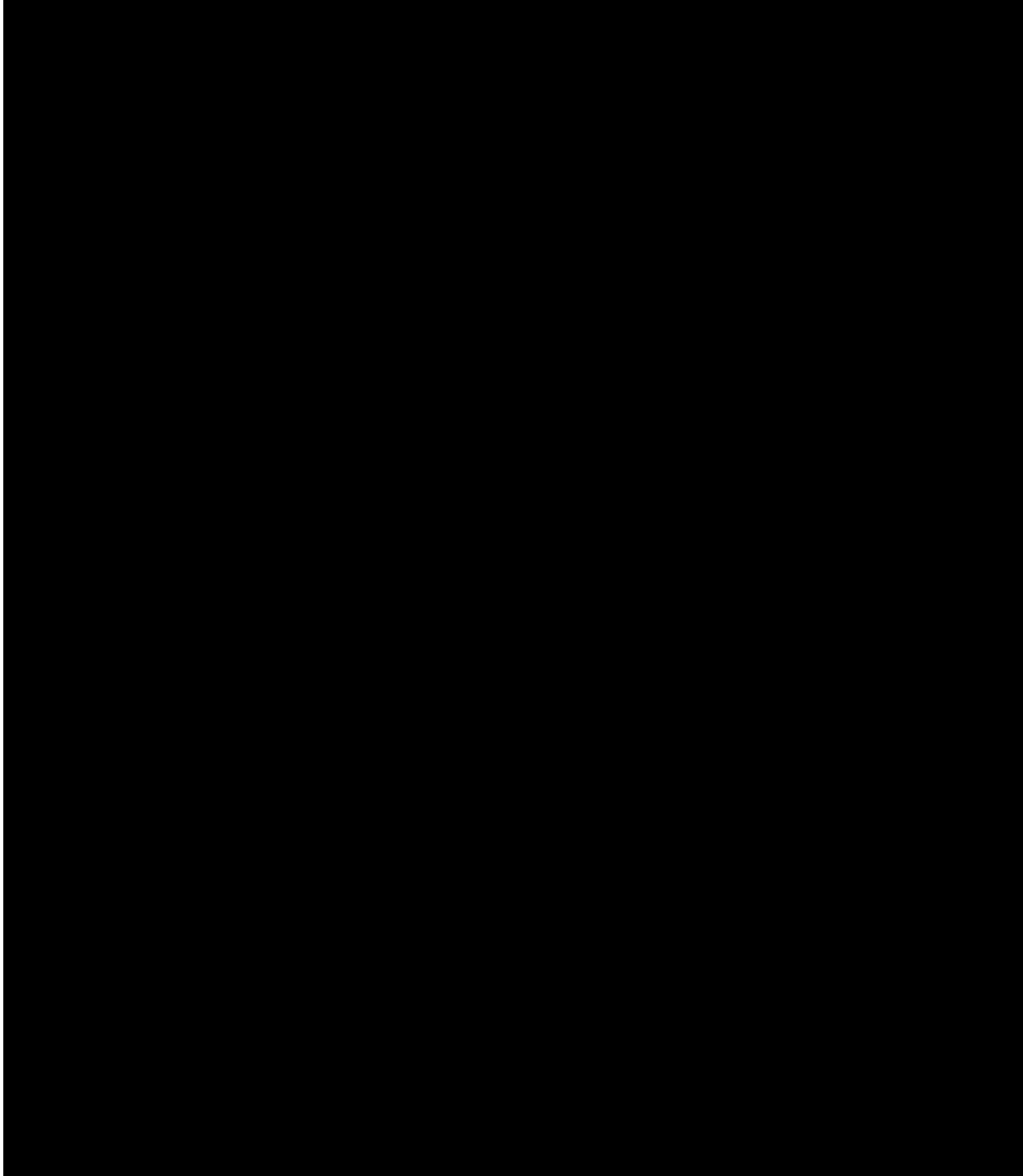


Claimed as PBI

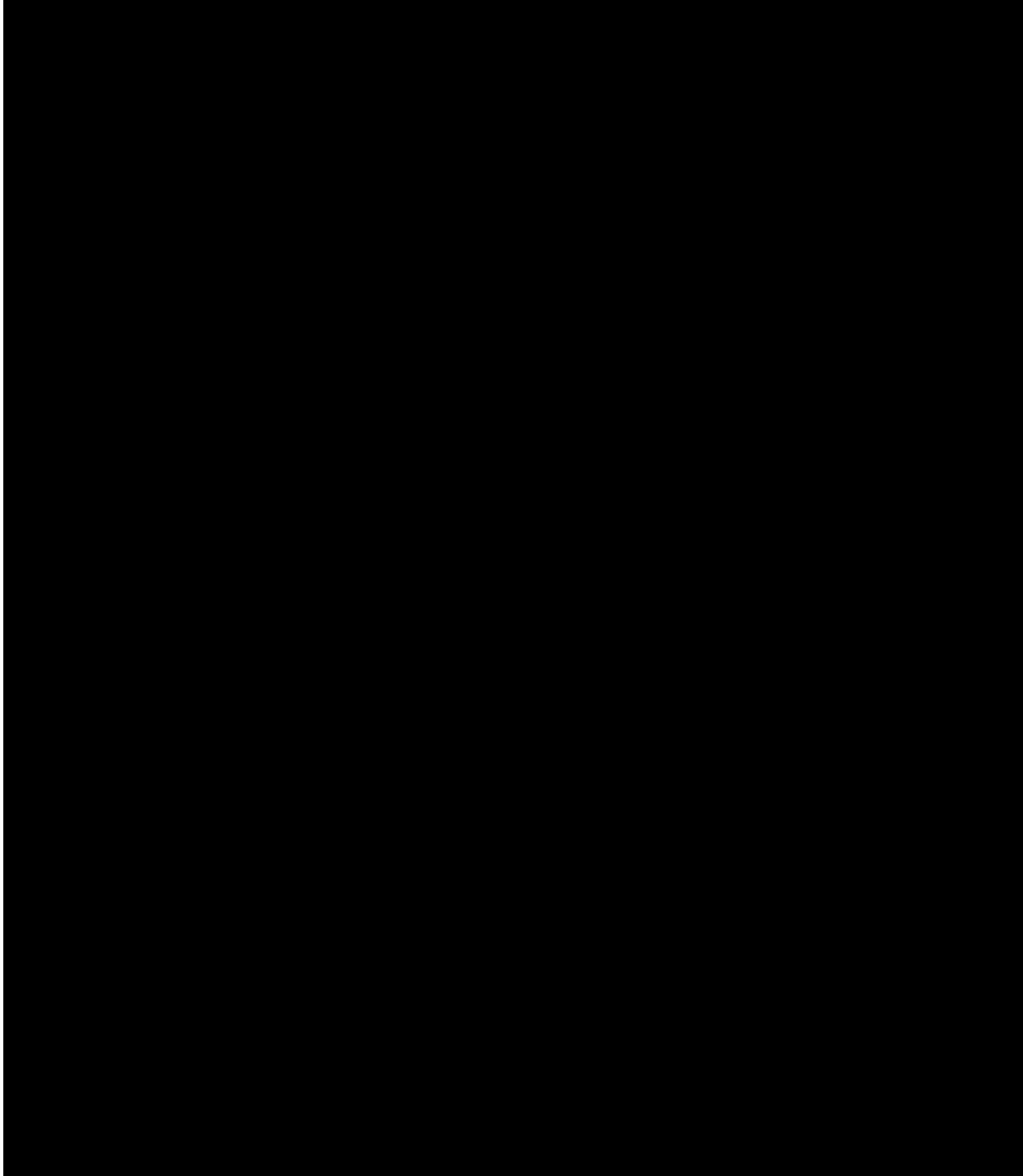


Claimed as PBI

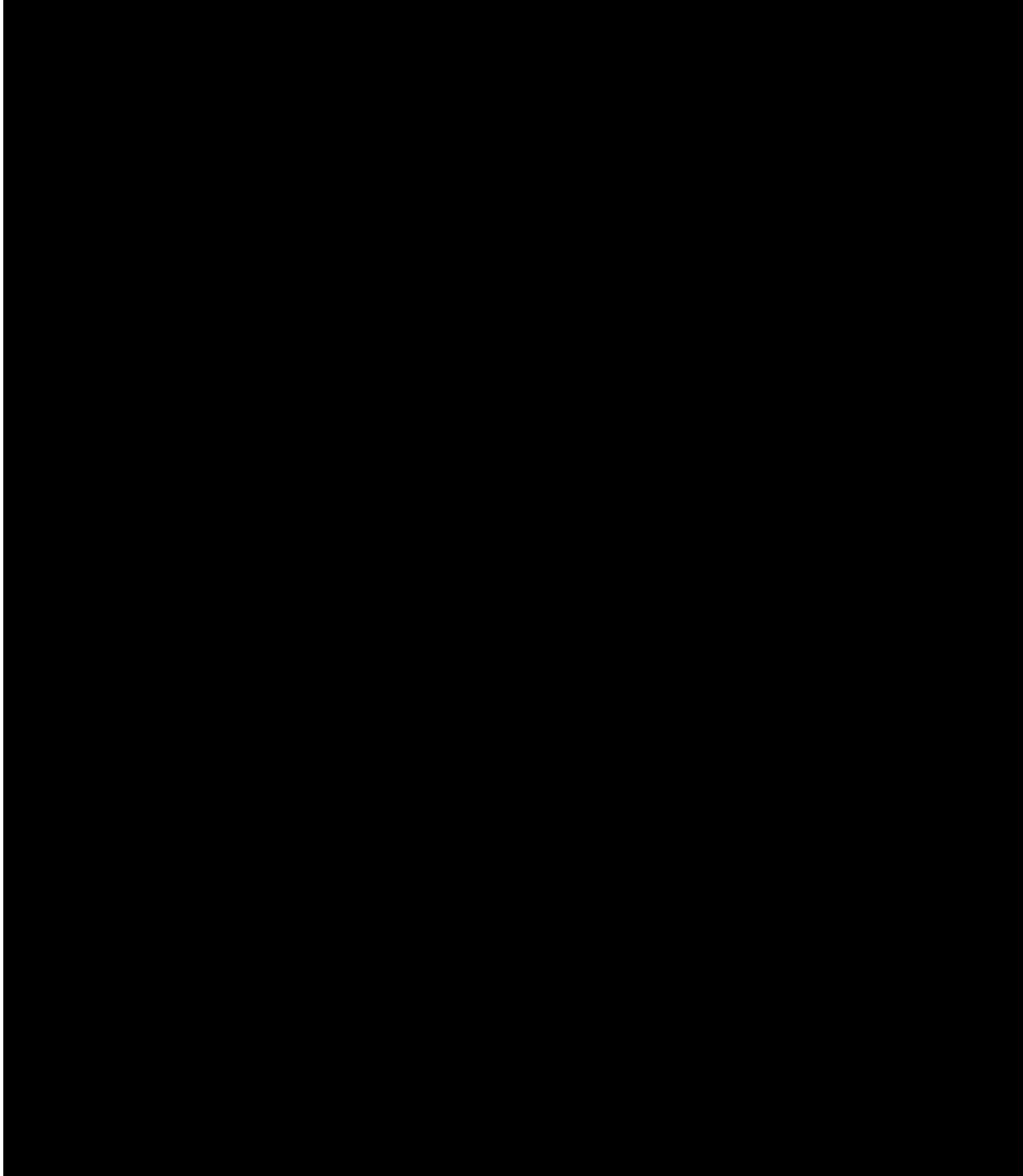
Claimed as PBI



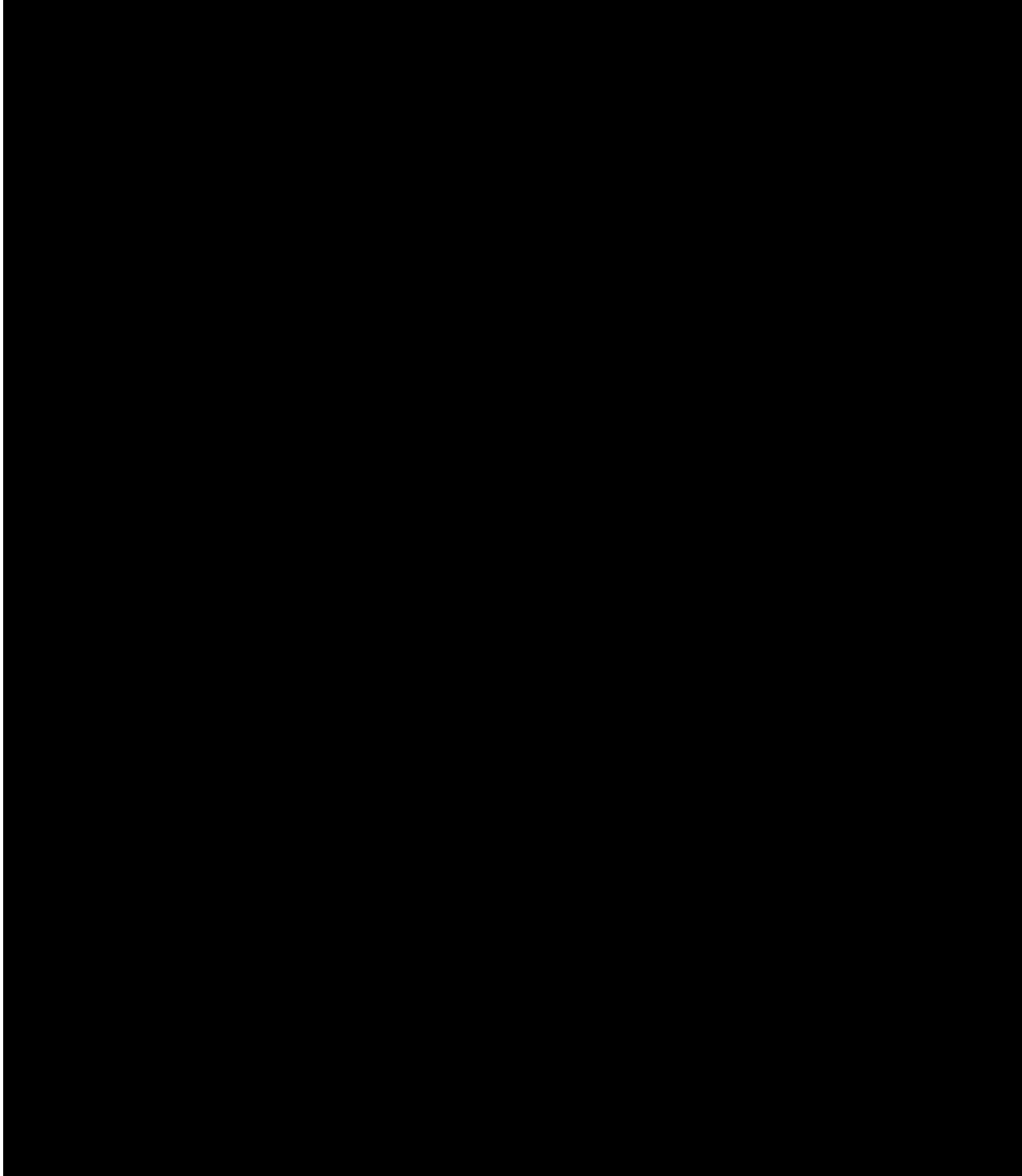
Claimed as PBI



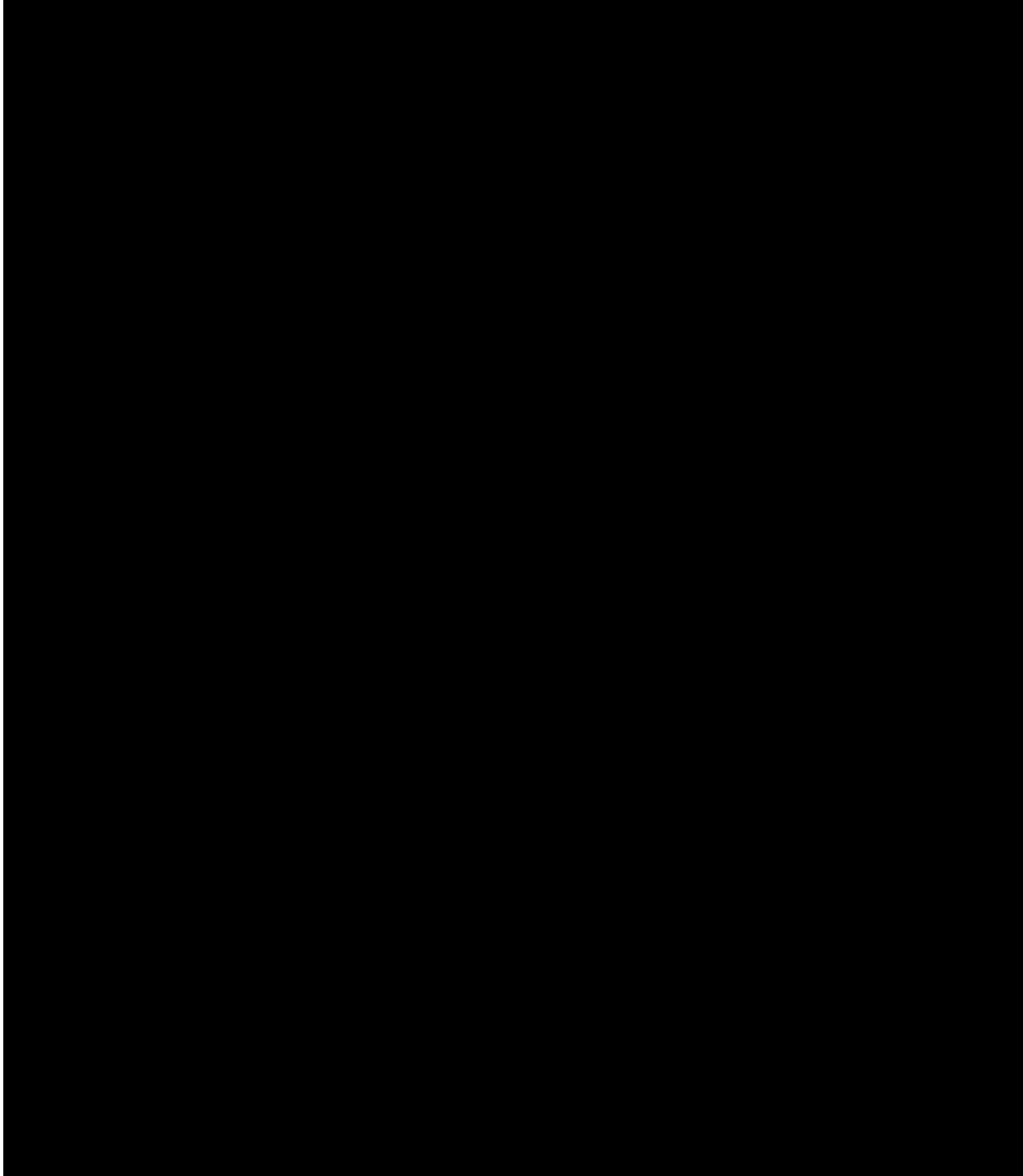
Claimed as PBI



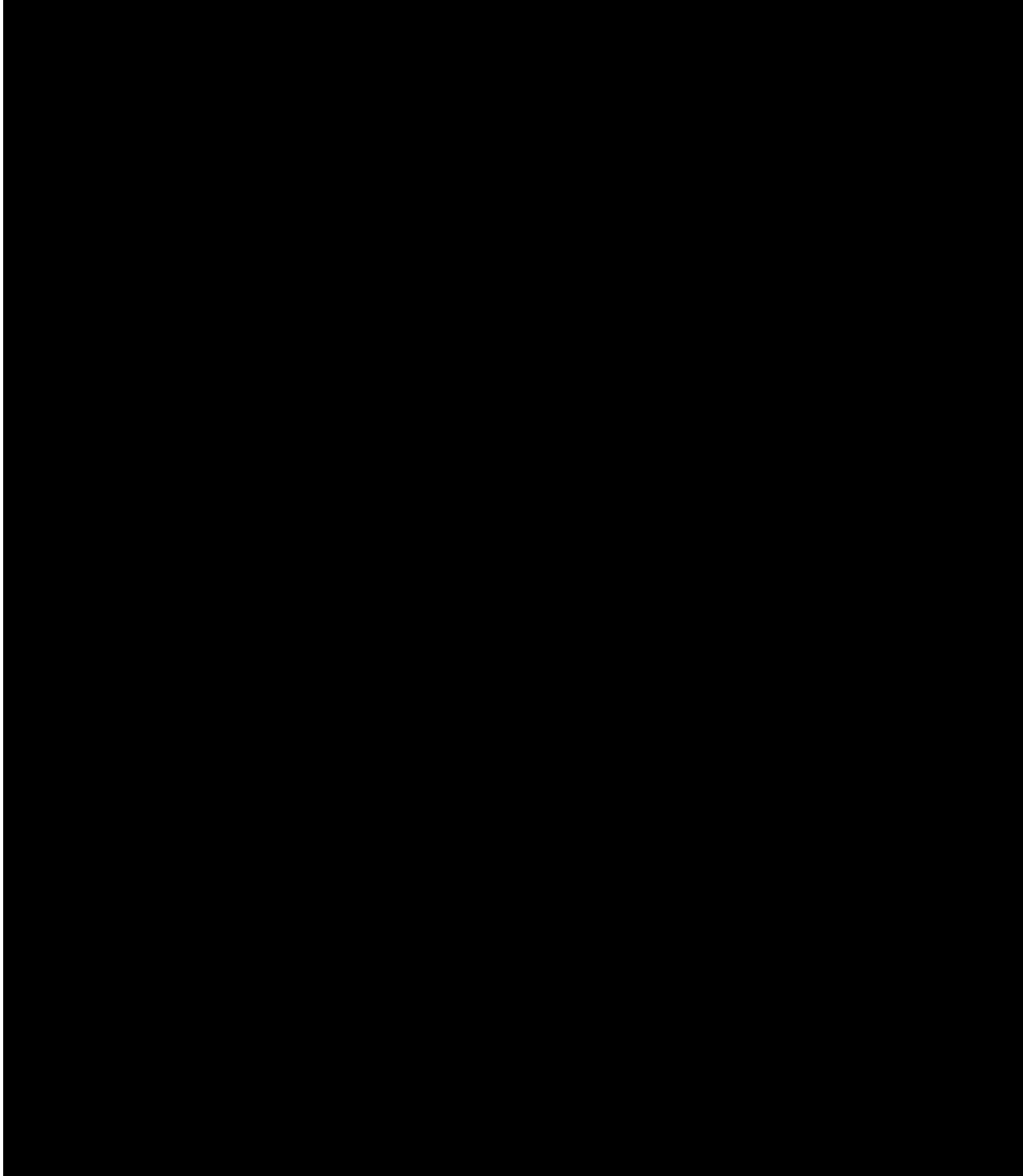
Claimed as PBI



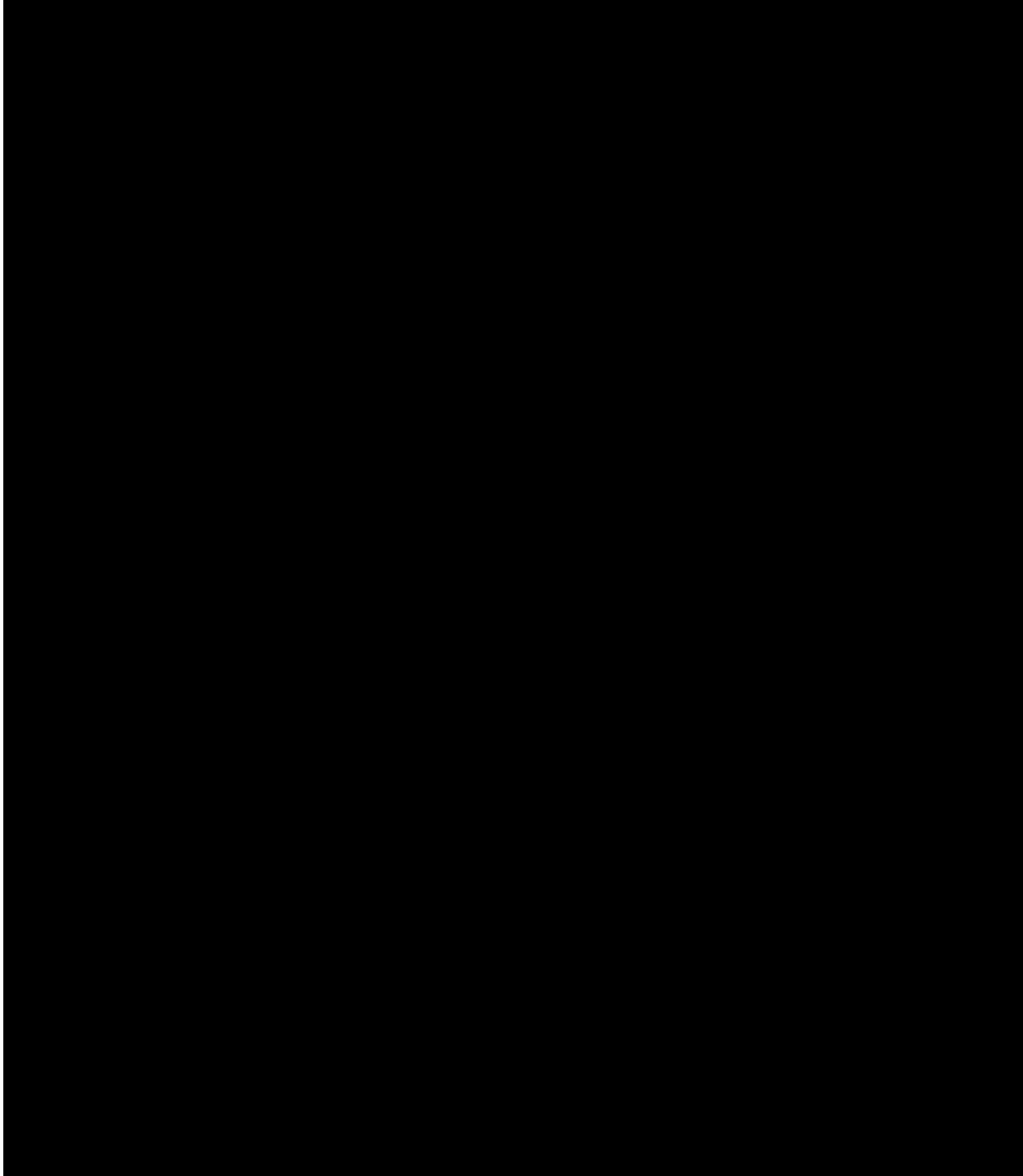
Claimed as PBI



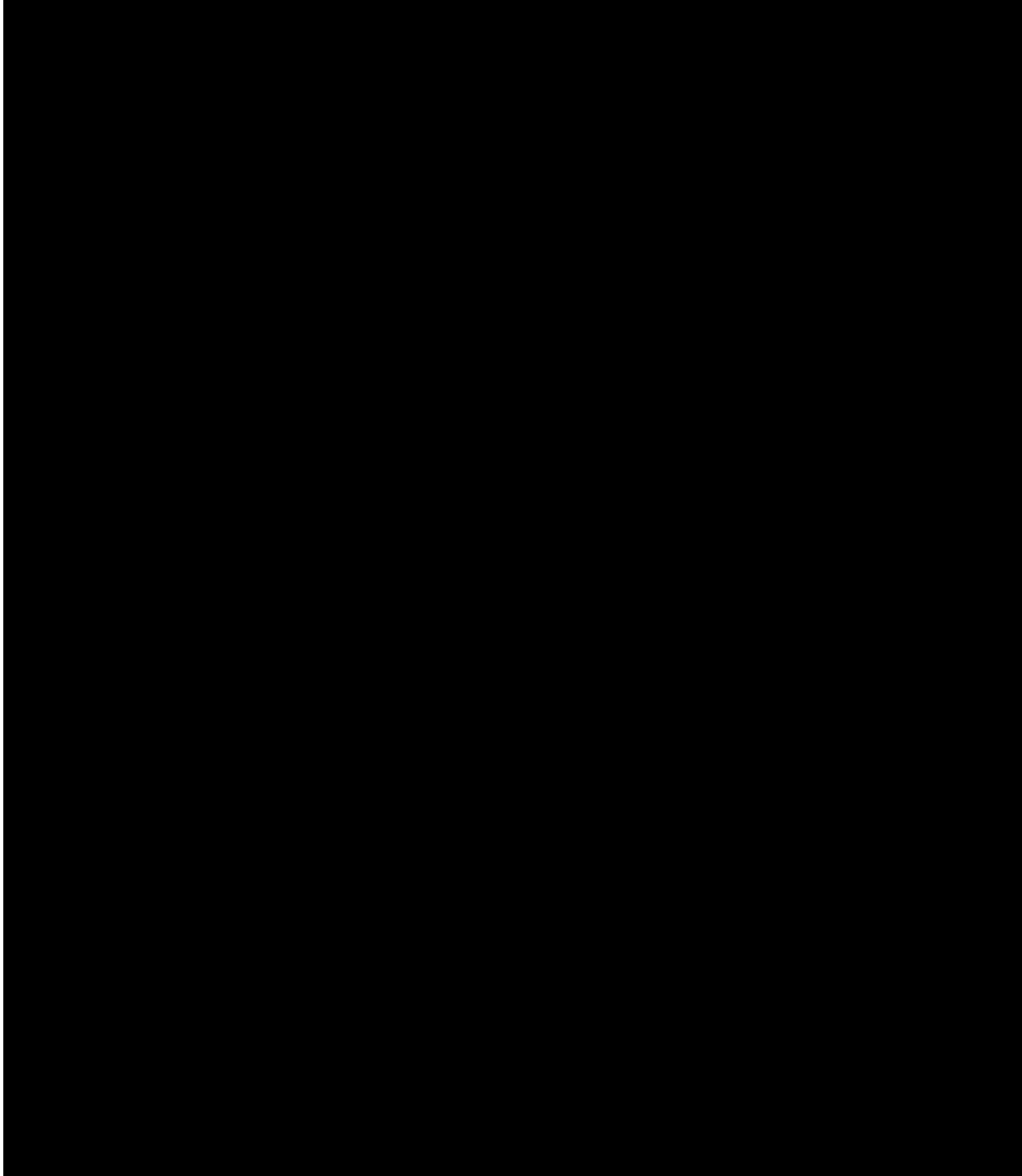
Claimed as PBI



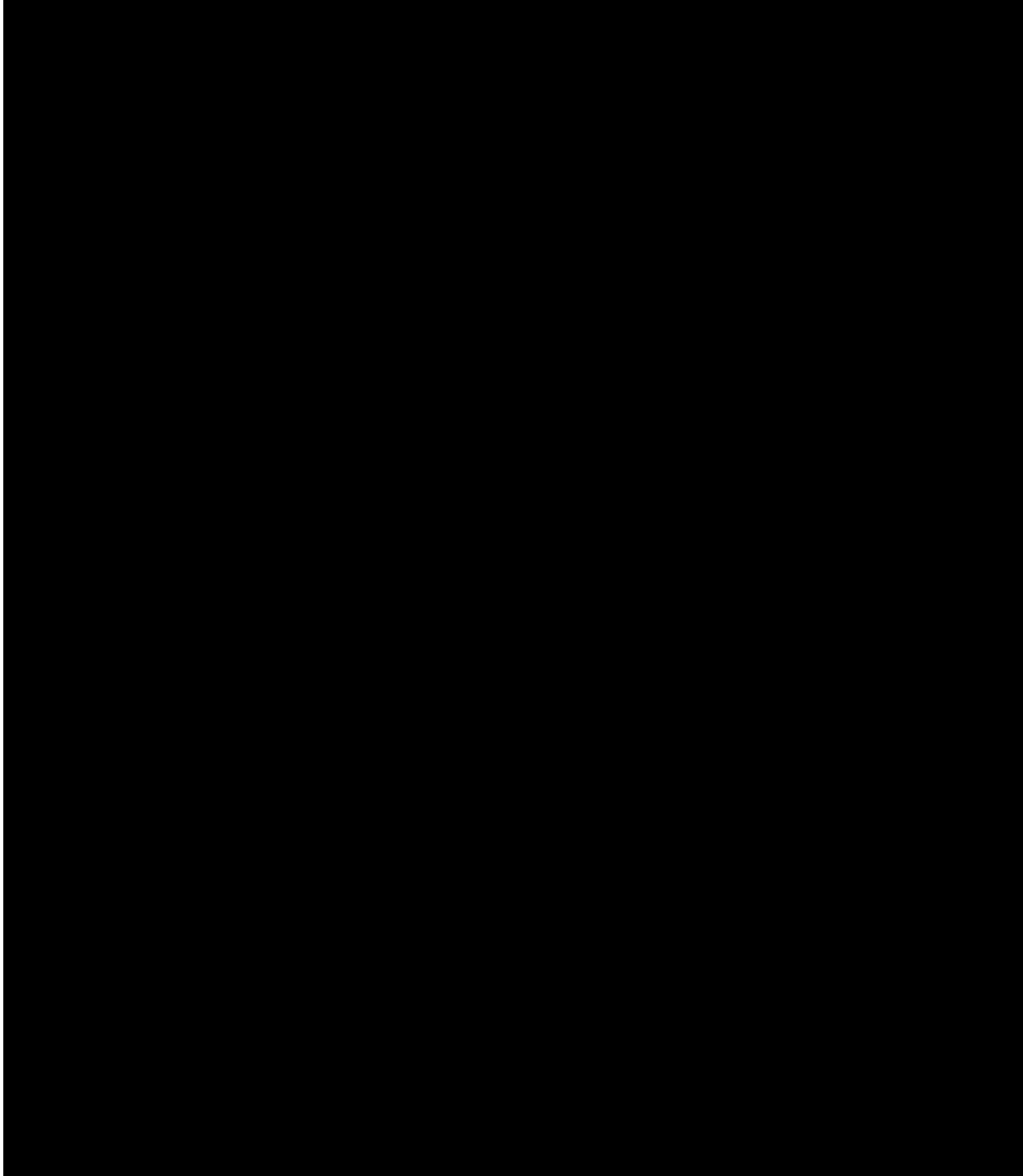
Claimed as PBI



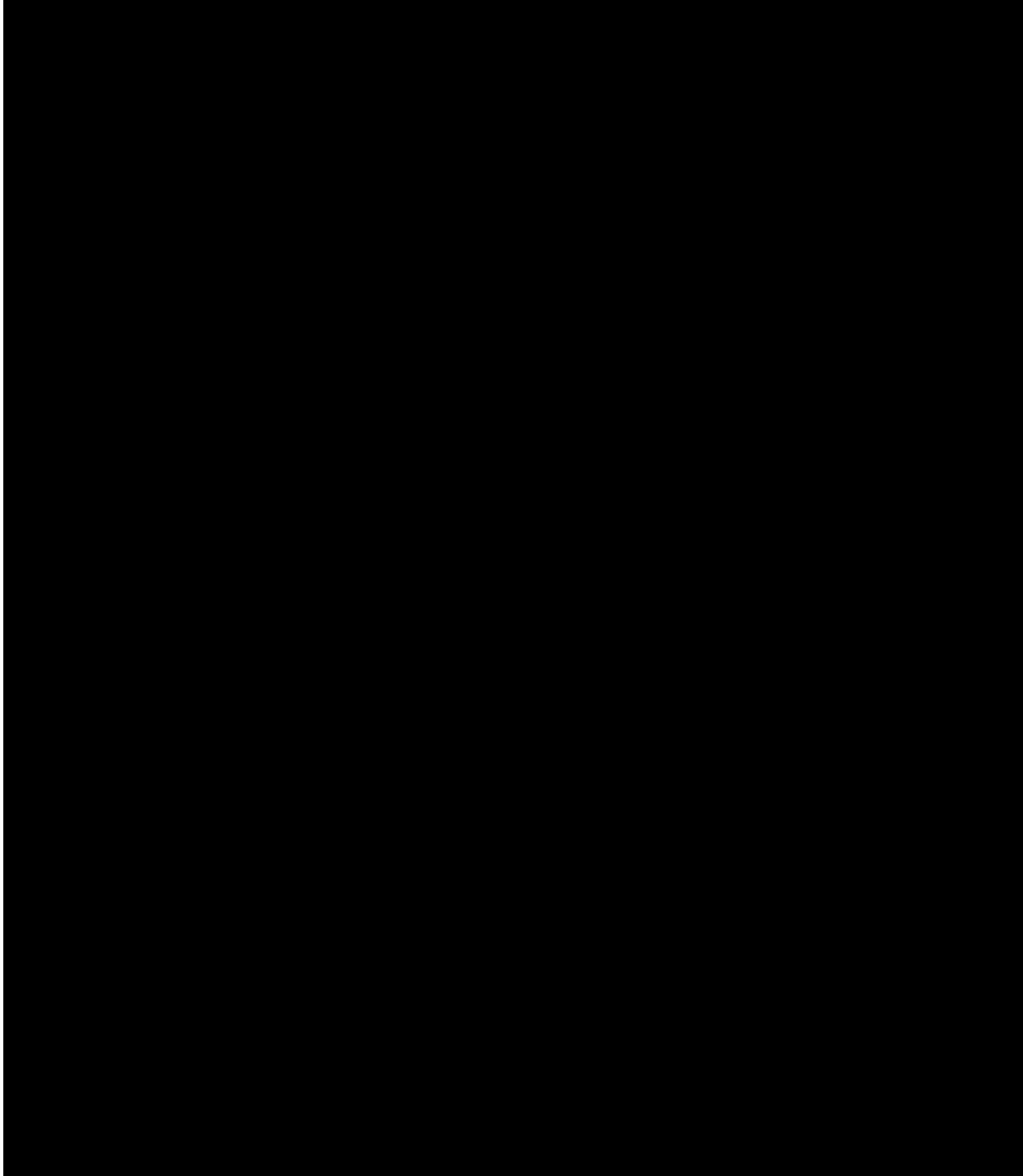
Claimed as PBI



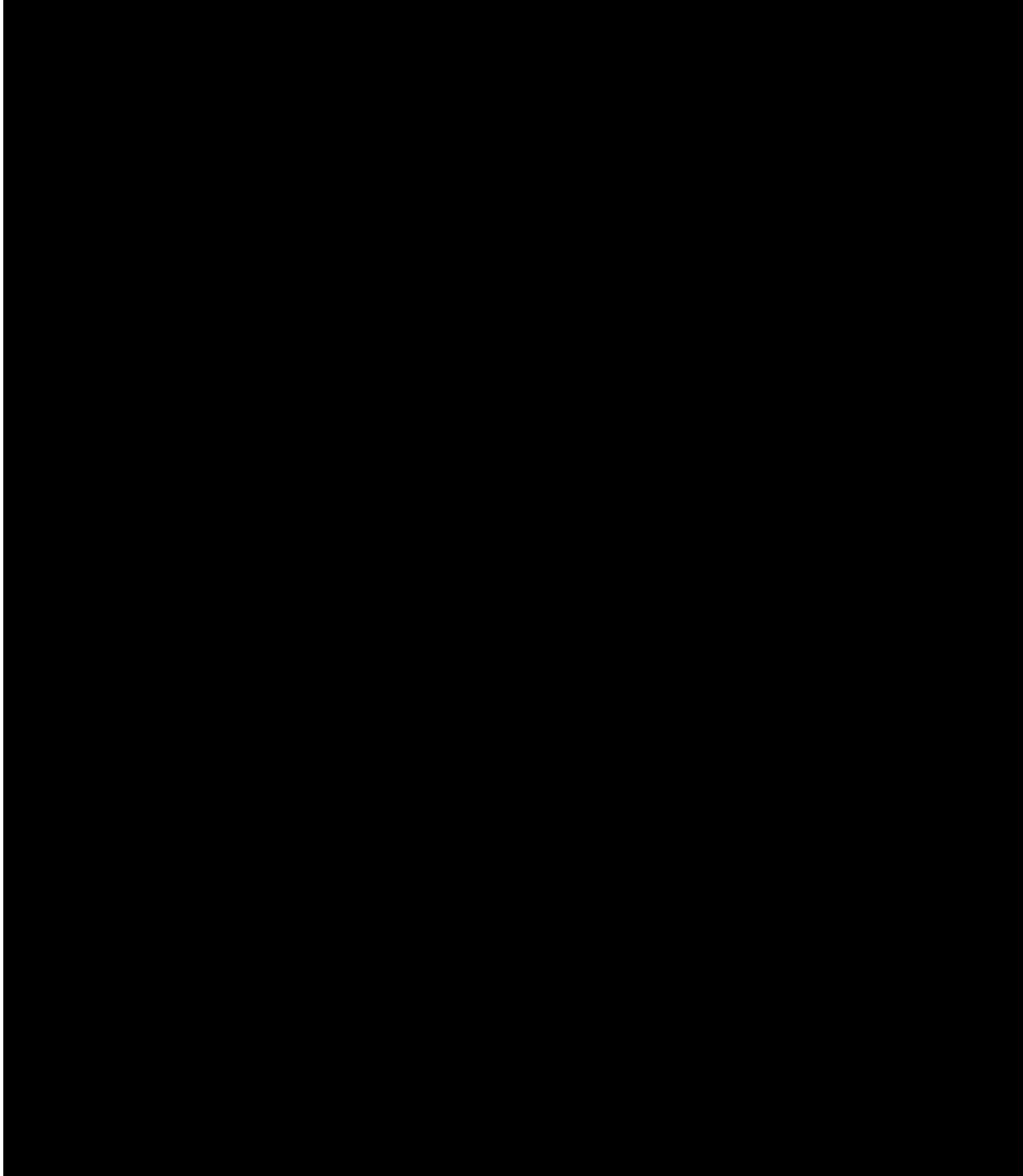
Claimed as PBI



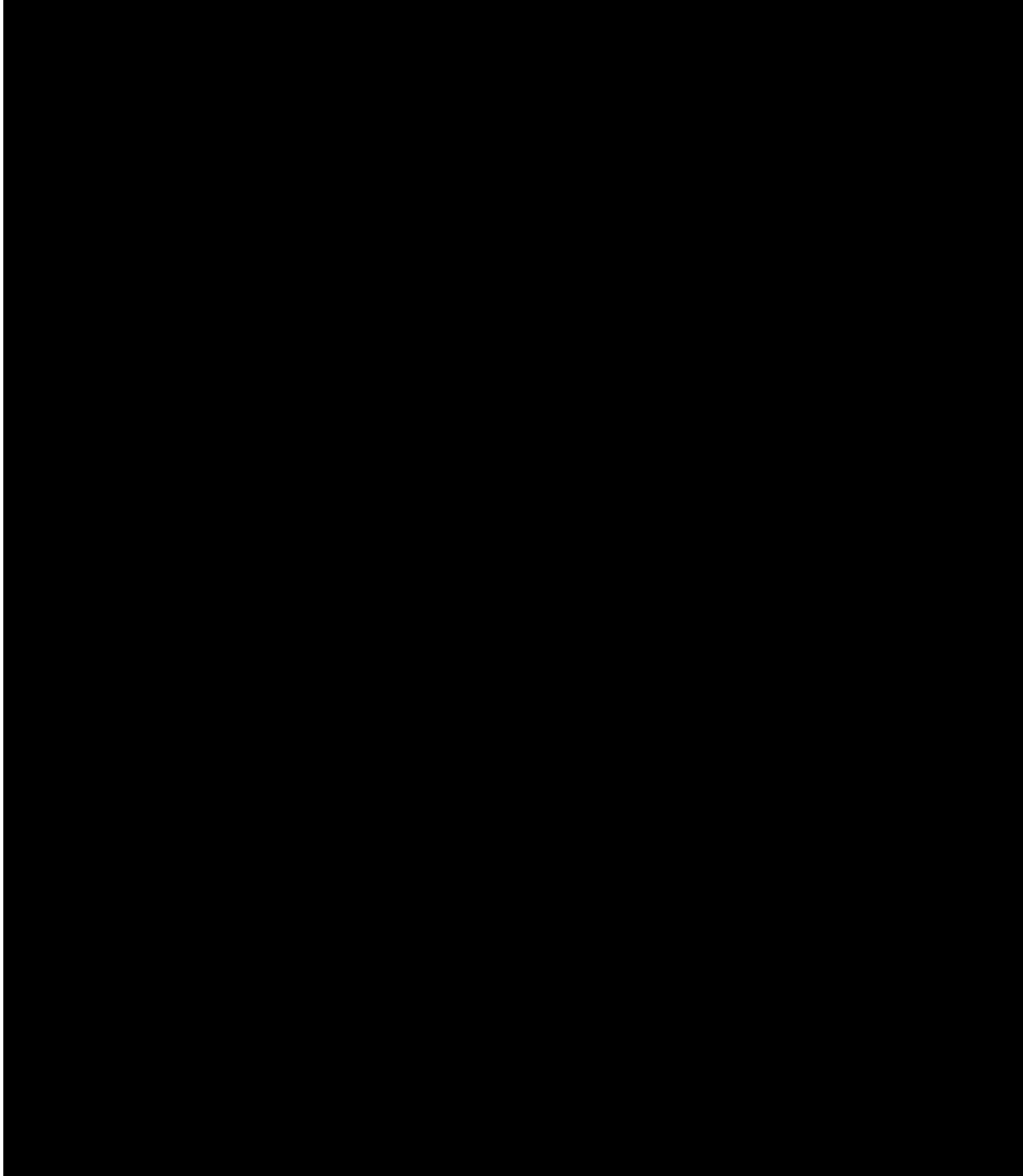
Claimed as PBI



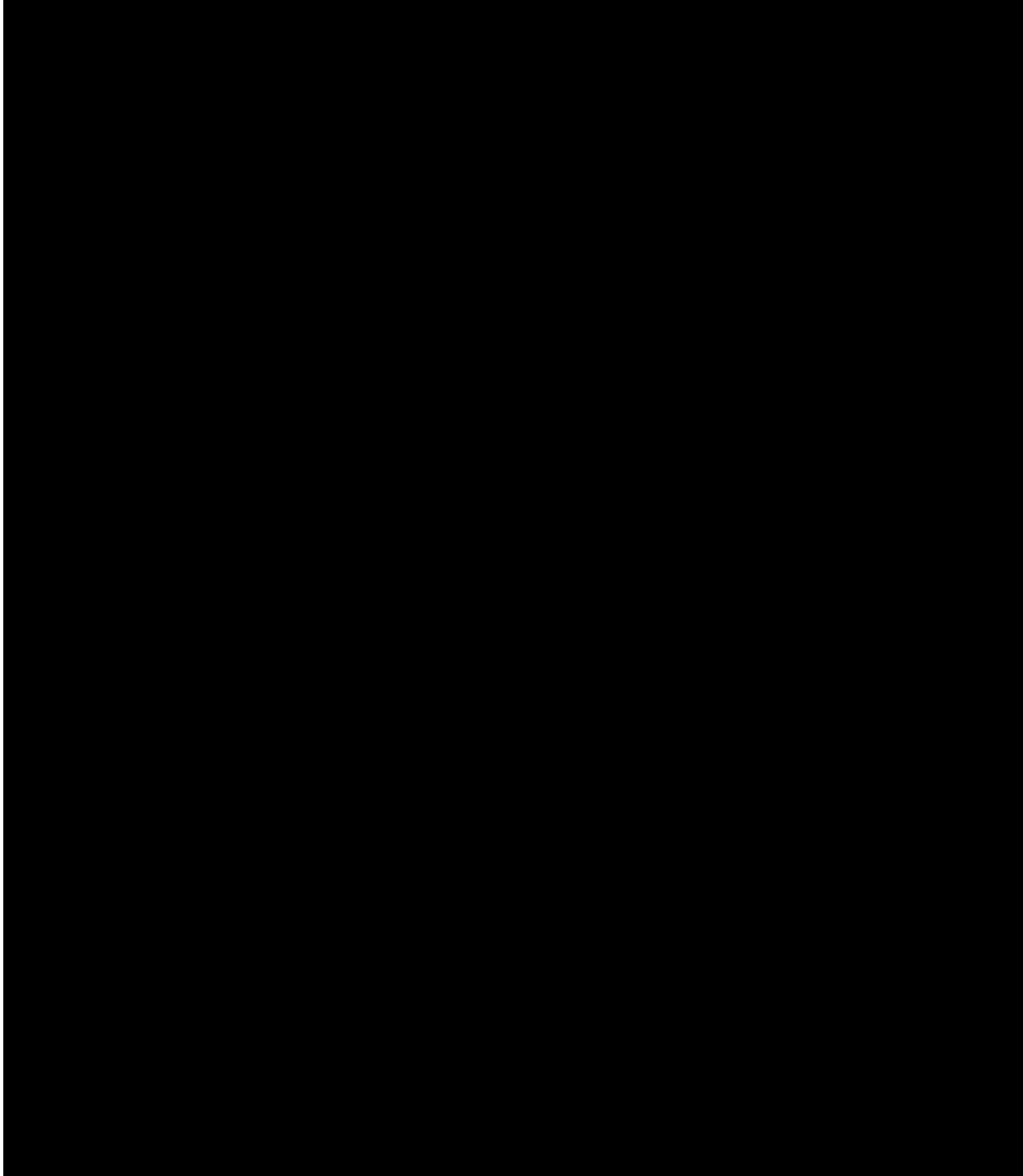
Claimed as PBI



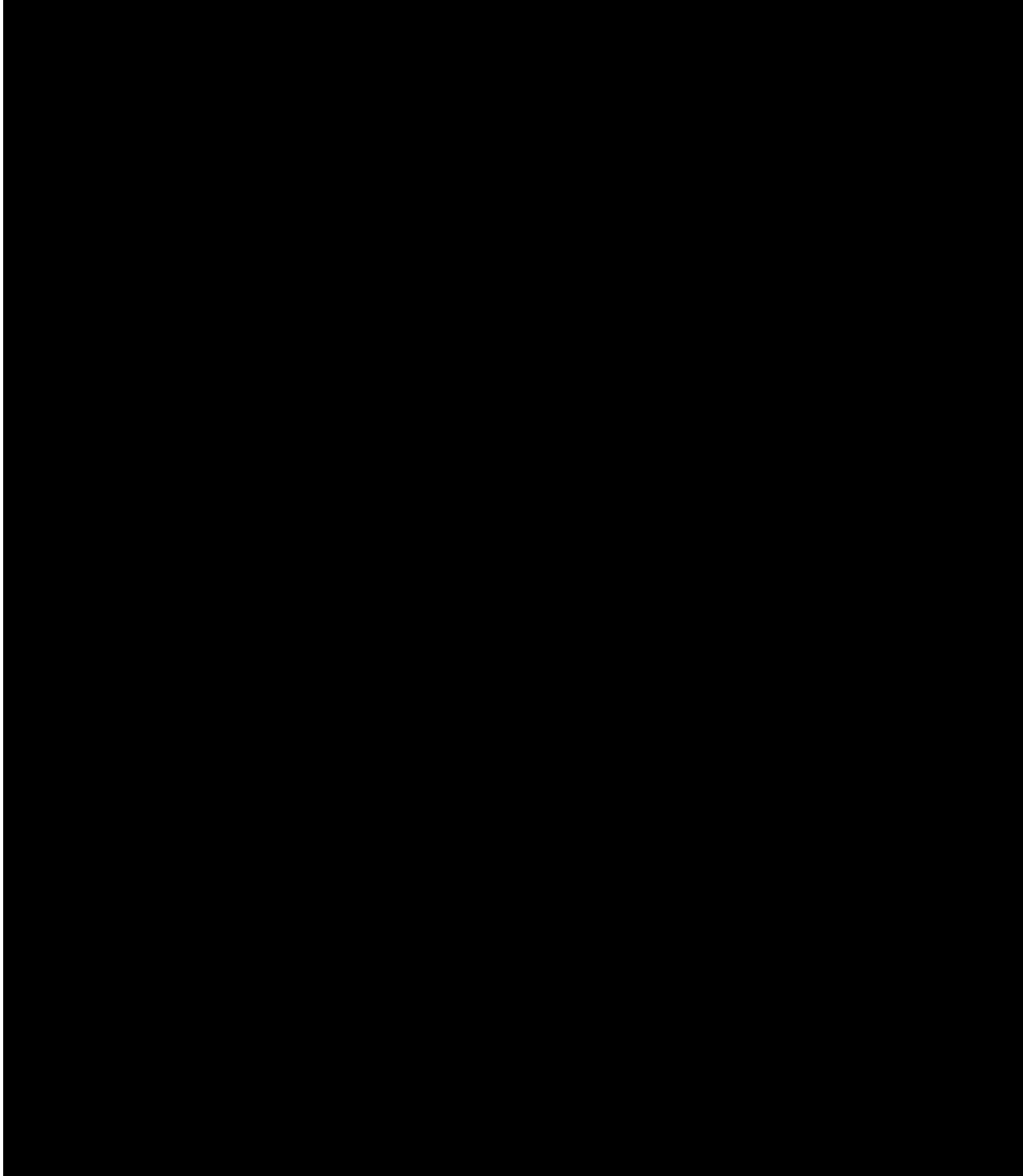
Claimed as PBI



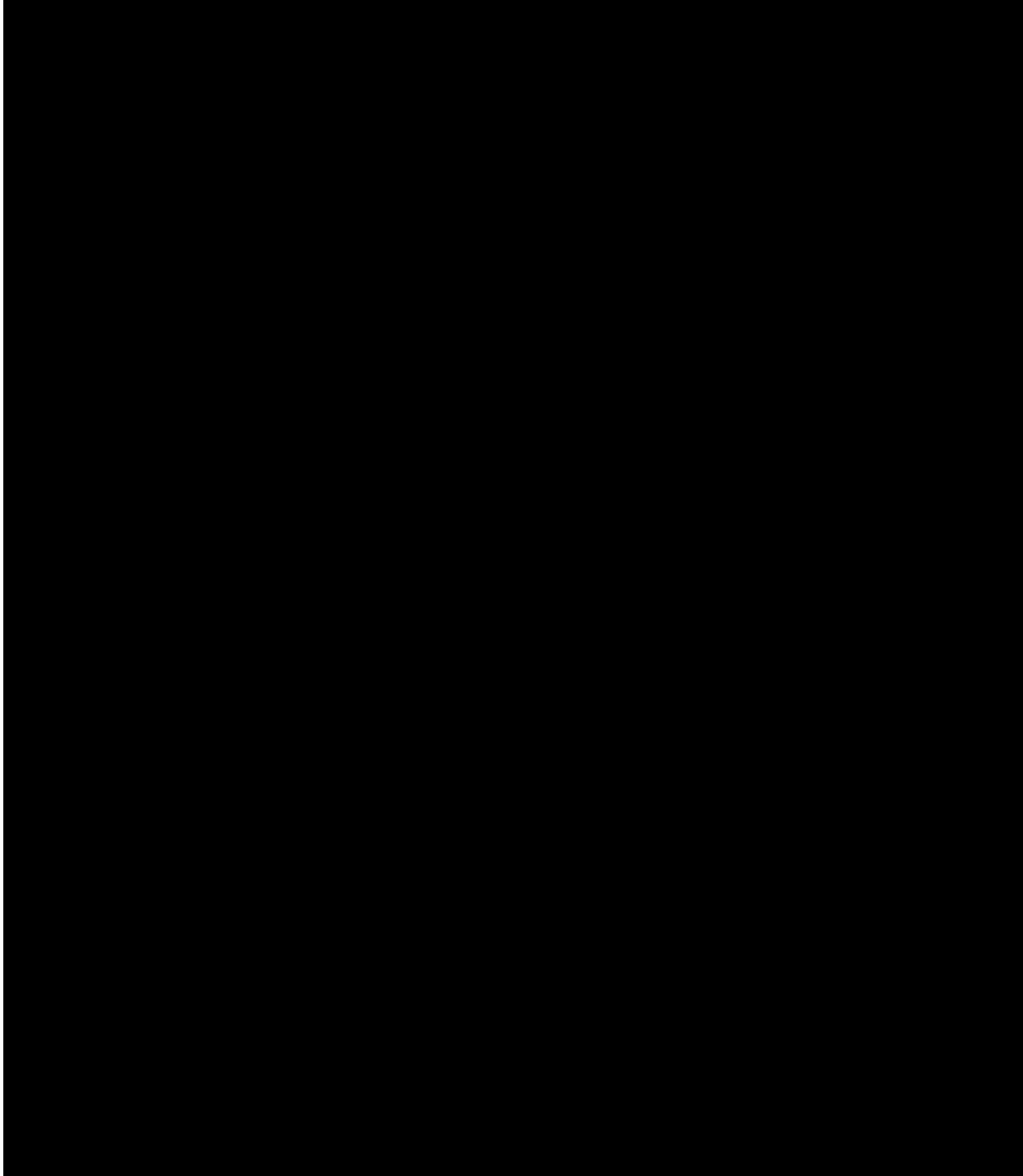
Claimed as PBI



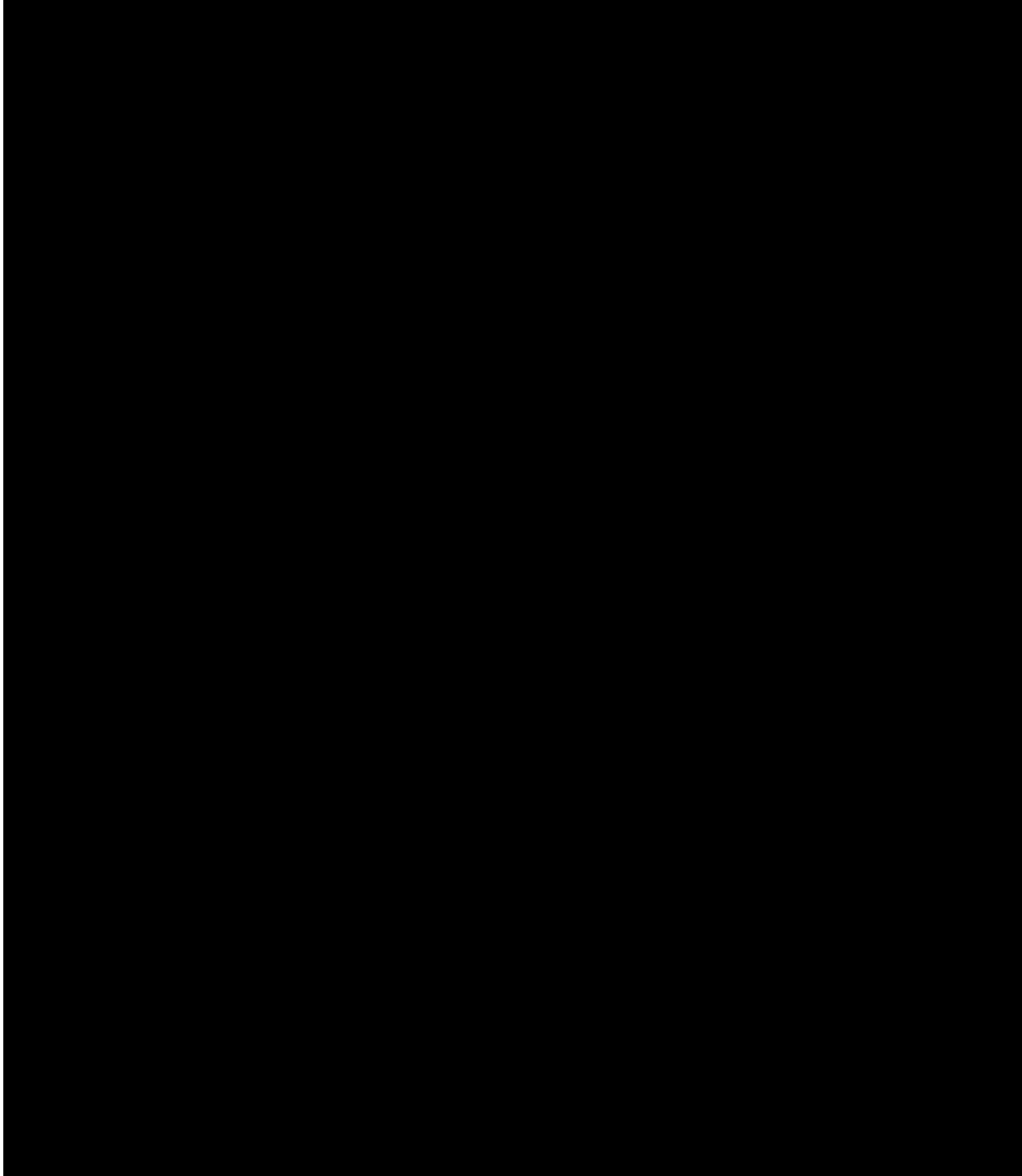
Claimed as PBI



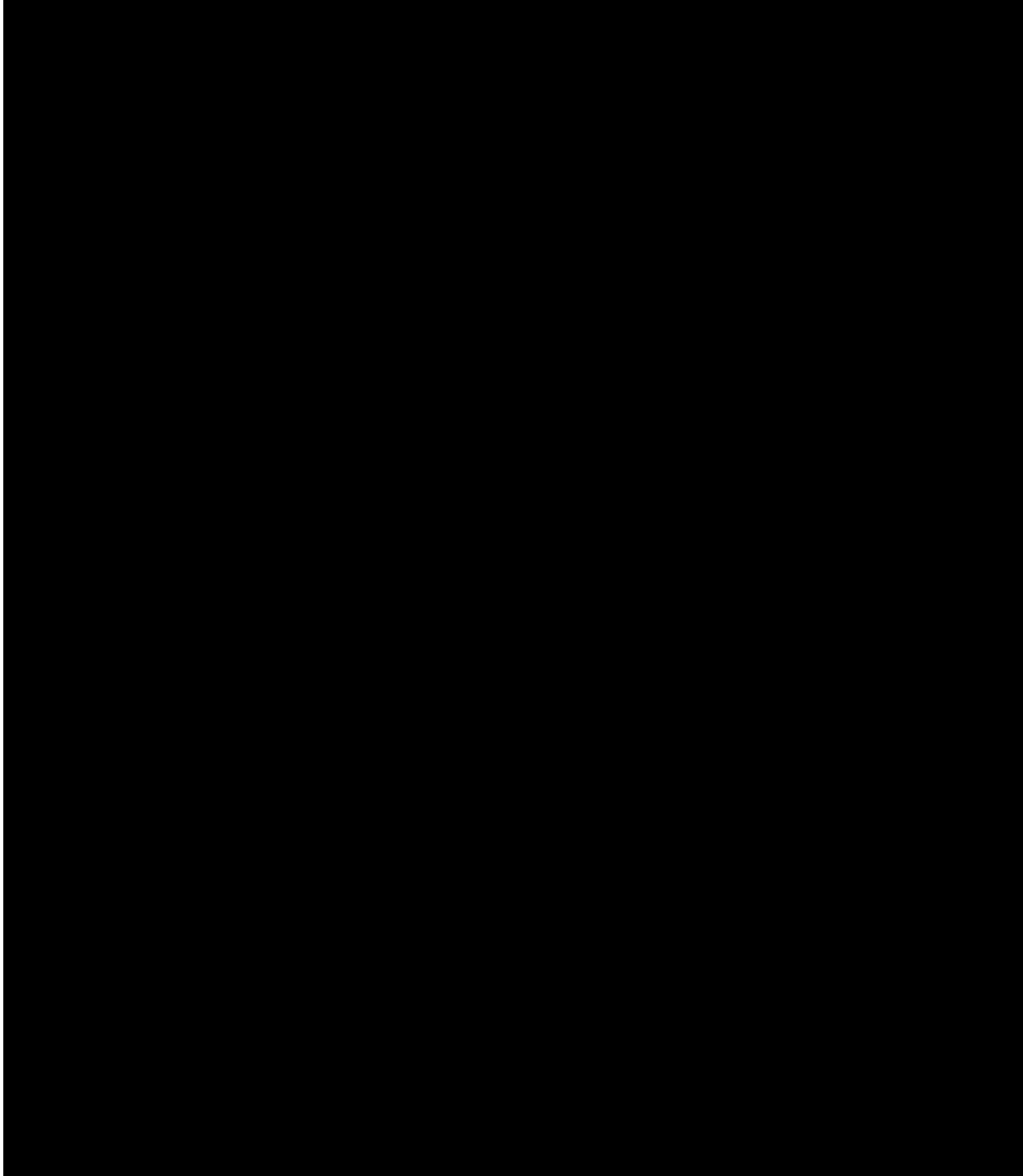
Claimed as PBI



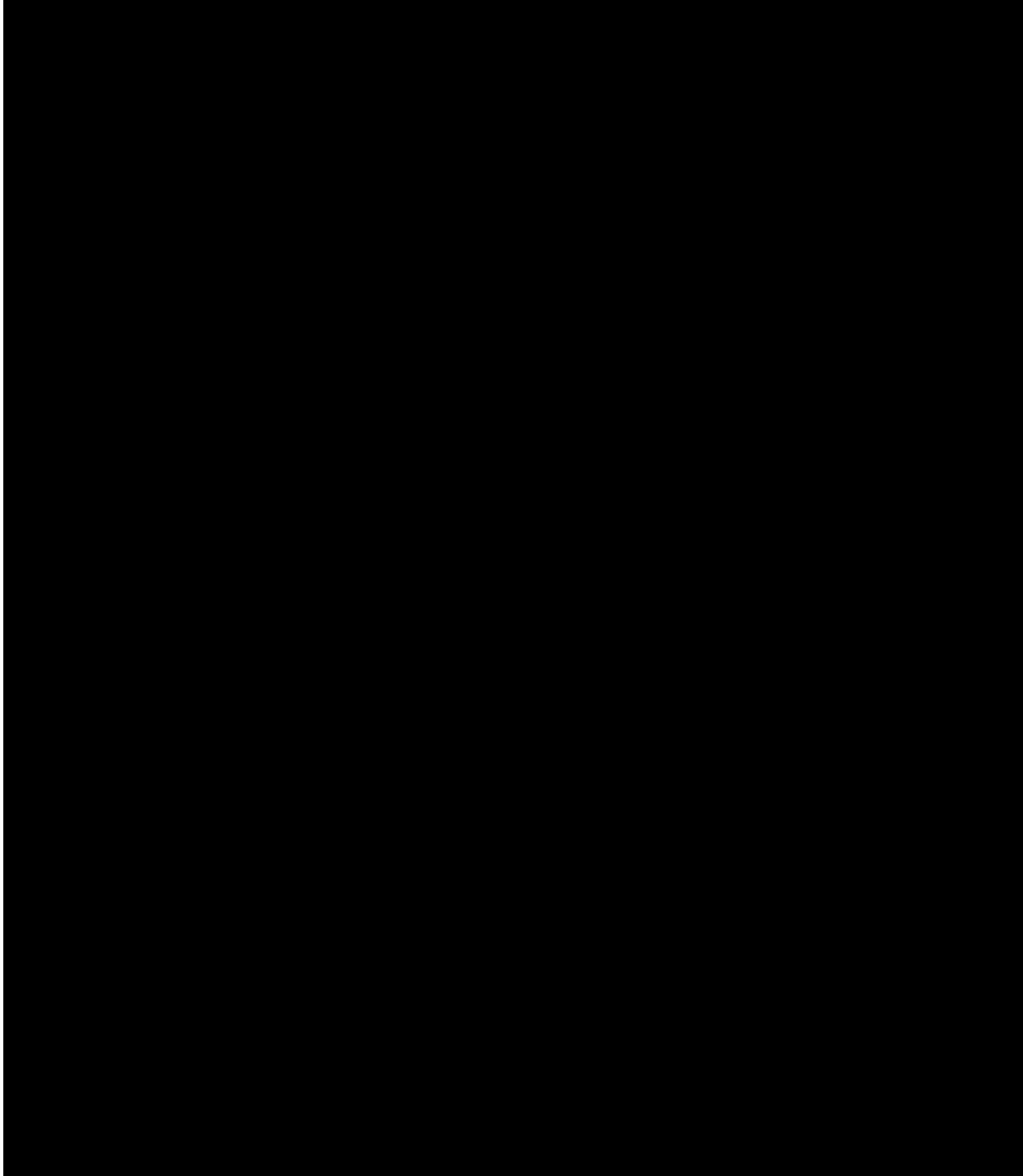
Claimed as PBI



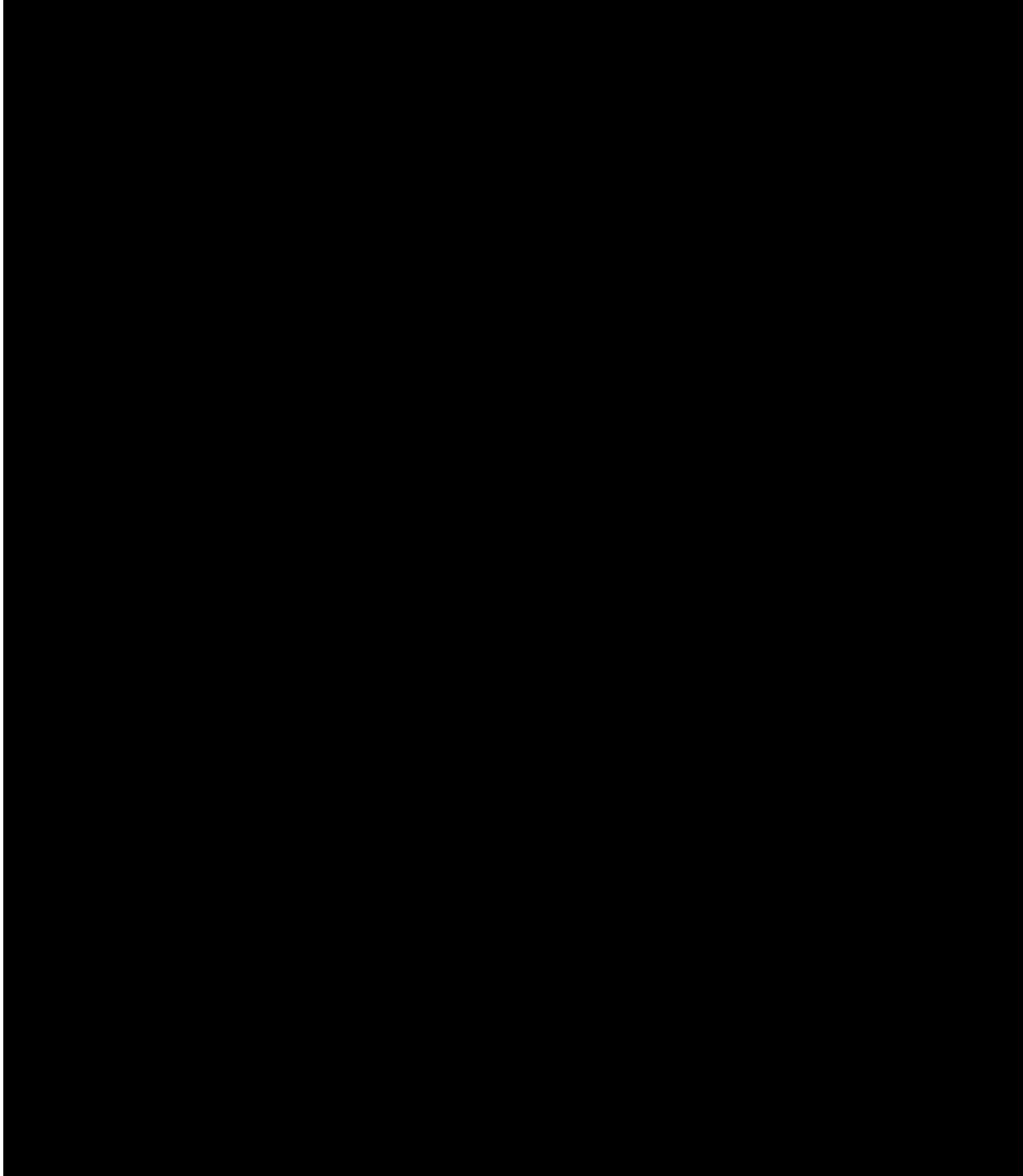
Claimed as PBI



Claimed as PBI

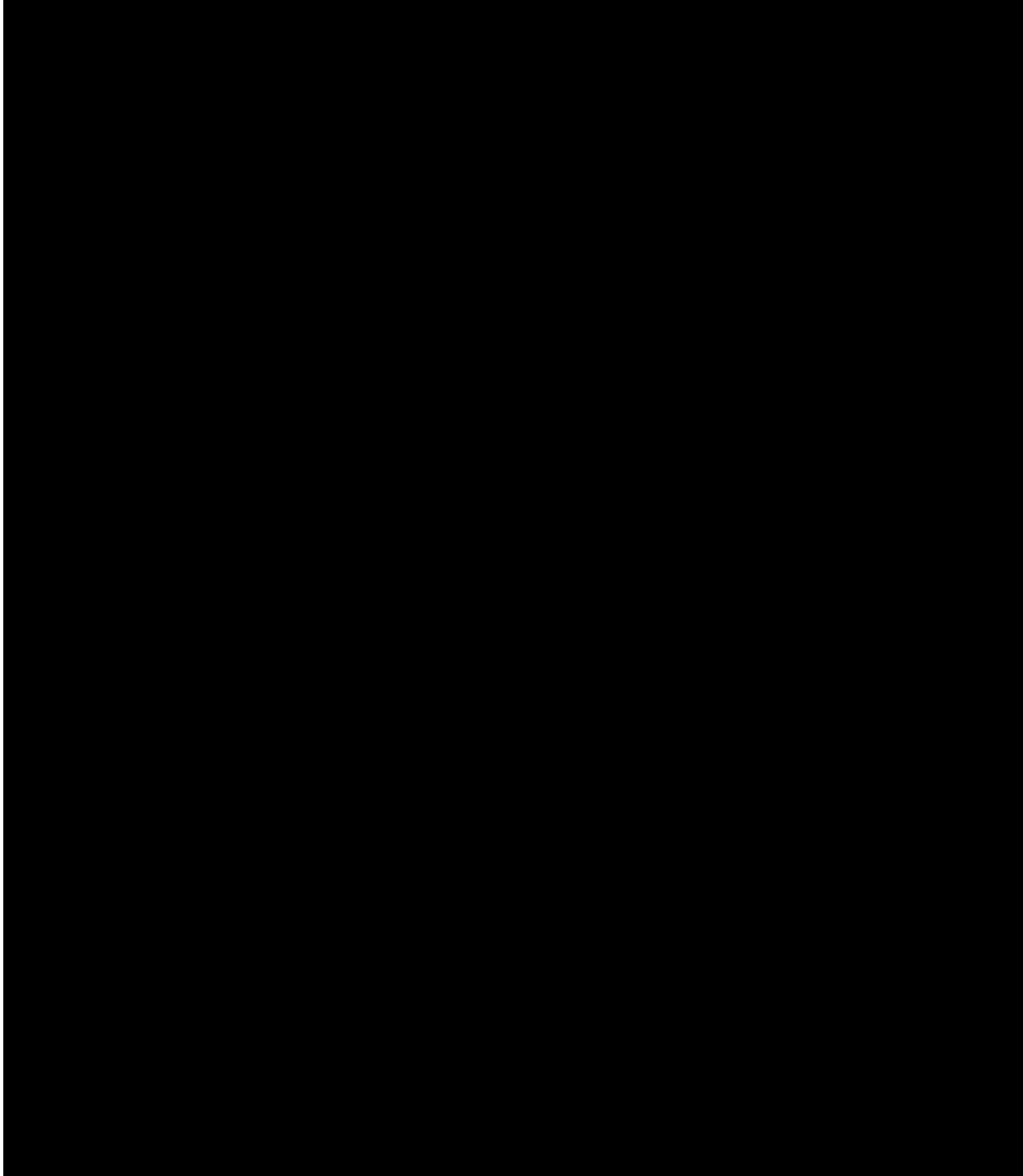


Claimed as PBI

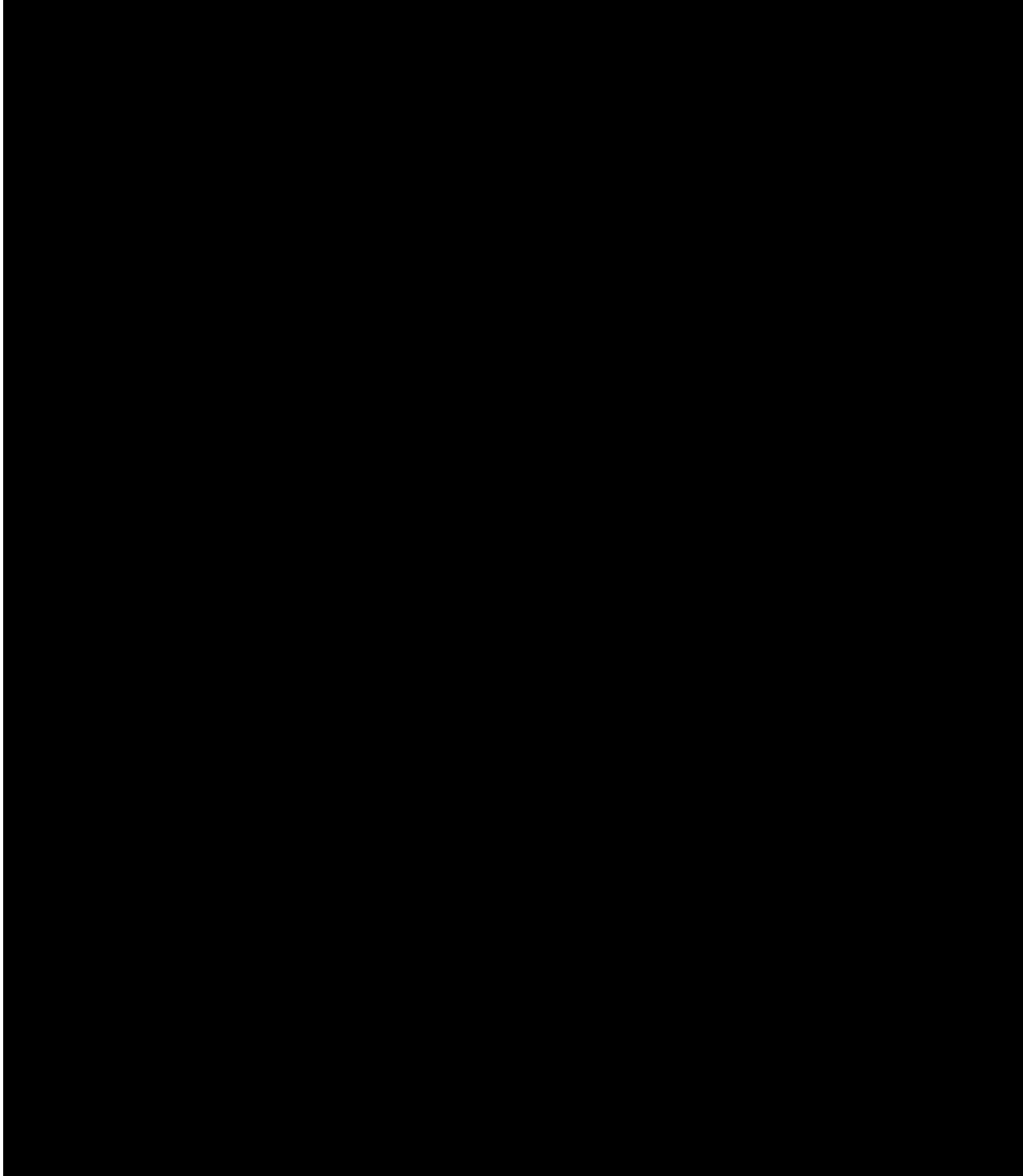


Claimed as PBI

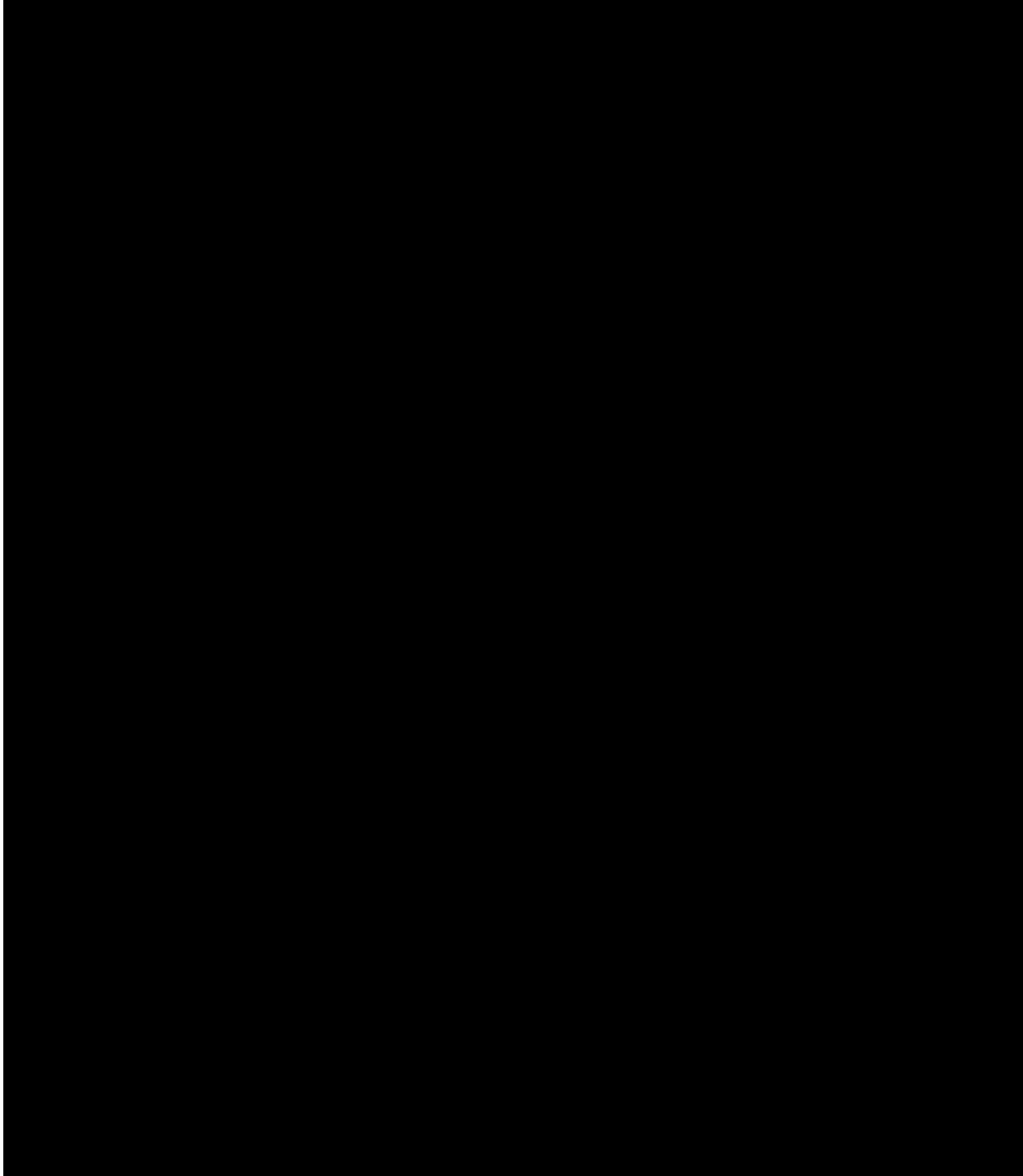
Claimed as PBI



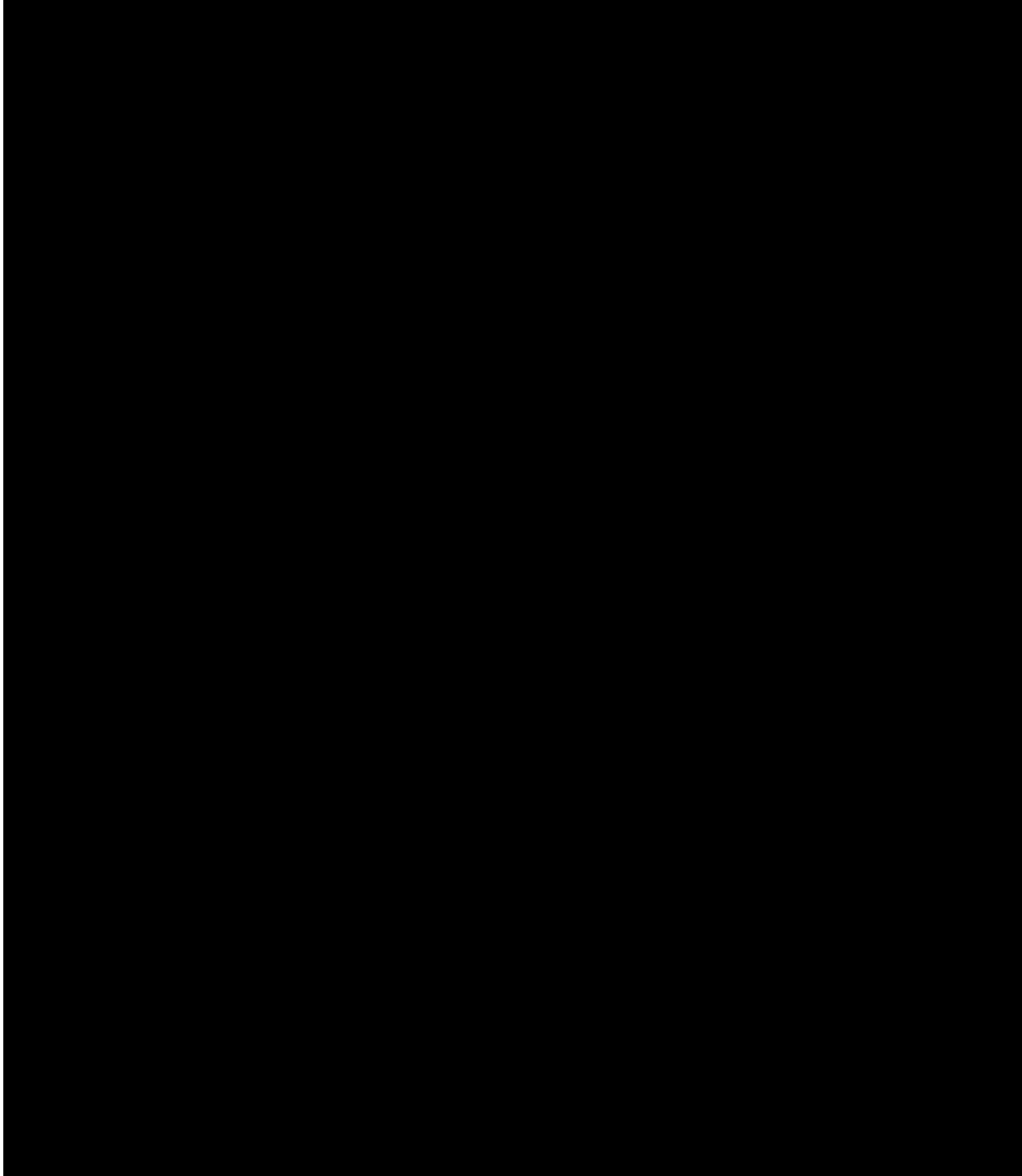
Claimed as PBI



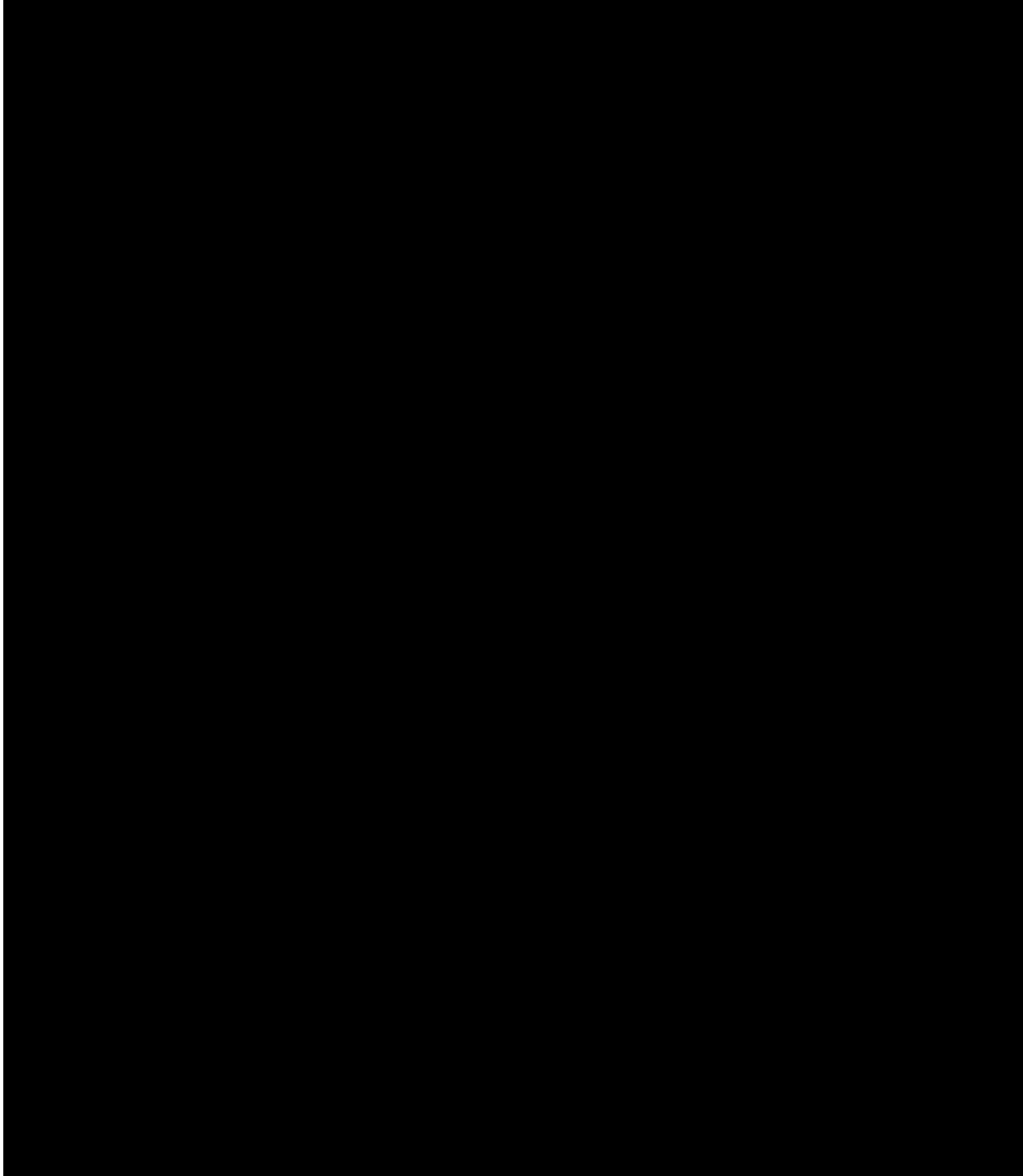
Claimed as PBI



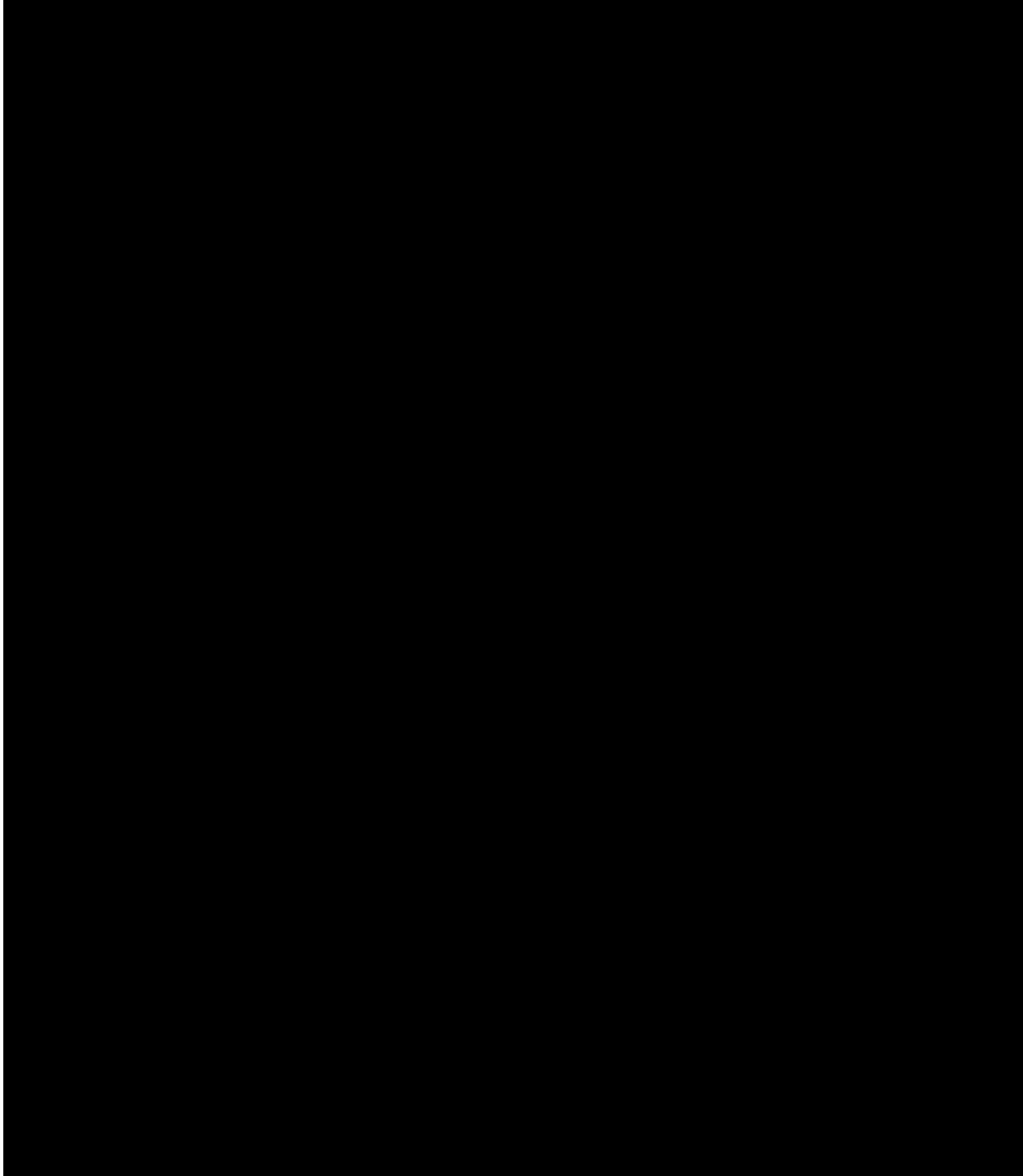
Claimed as PBI



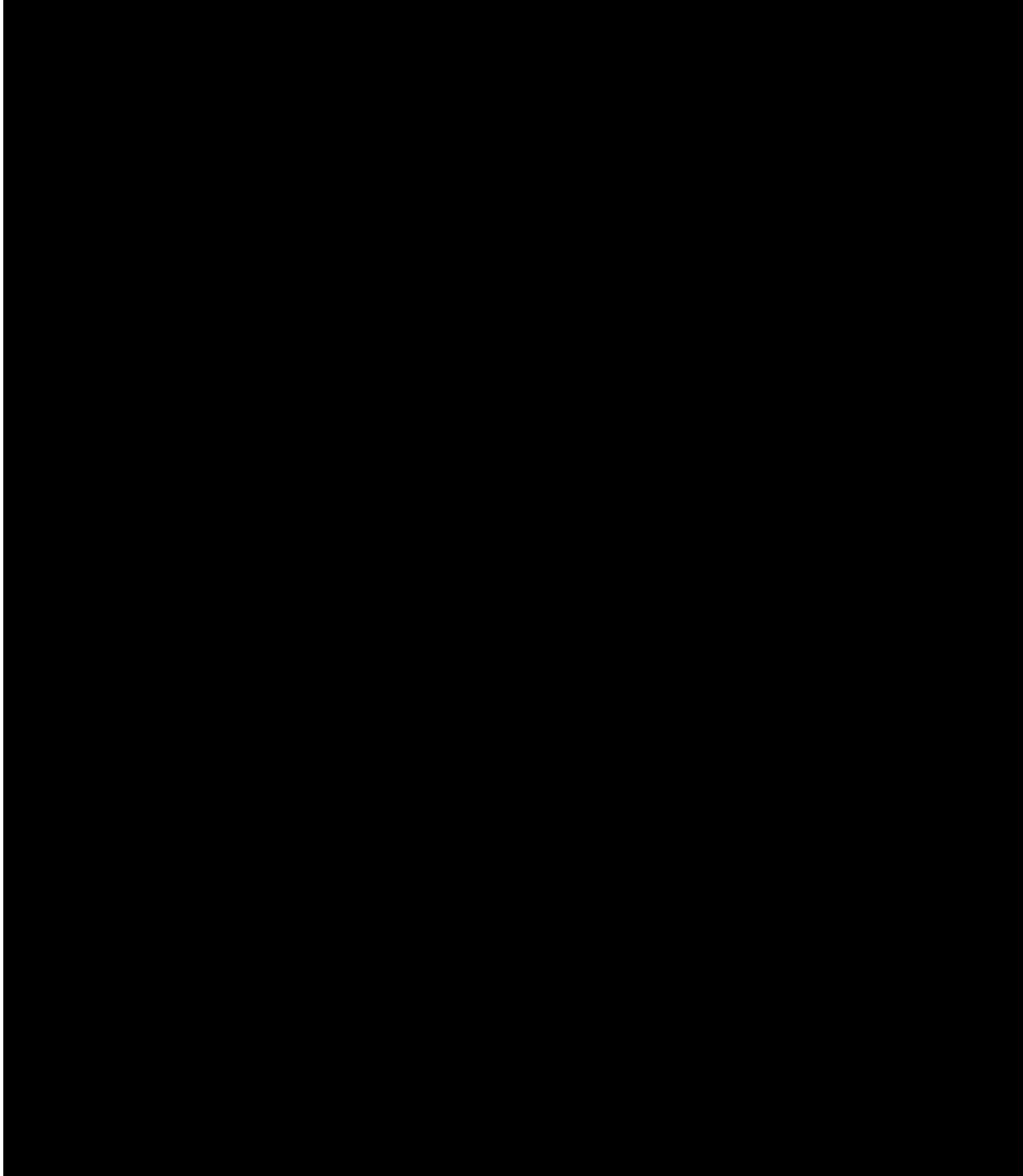
Claimed as PBI



Claimed as PBI

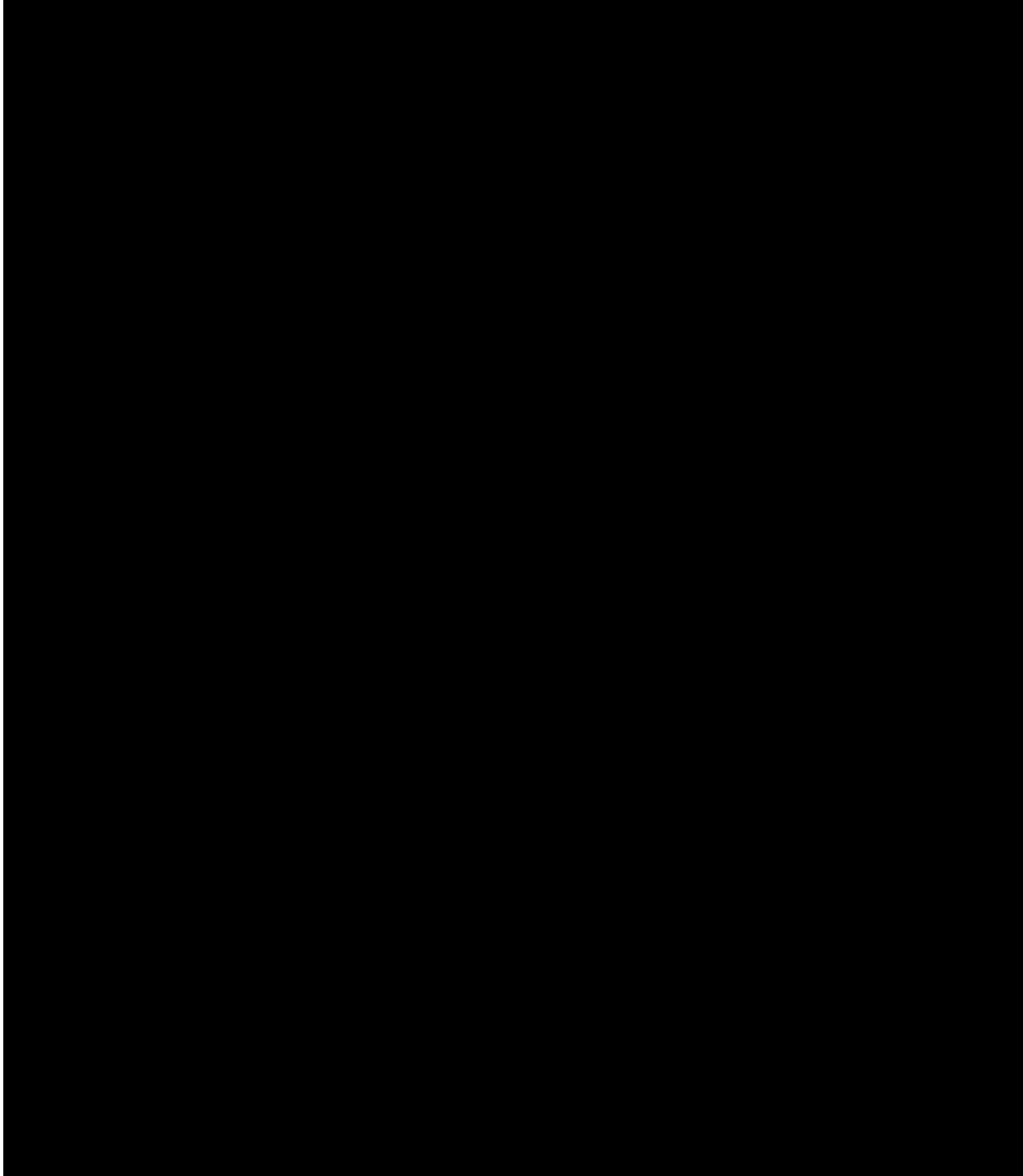


Claimed as PBI

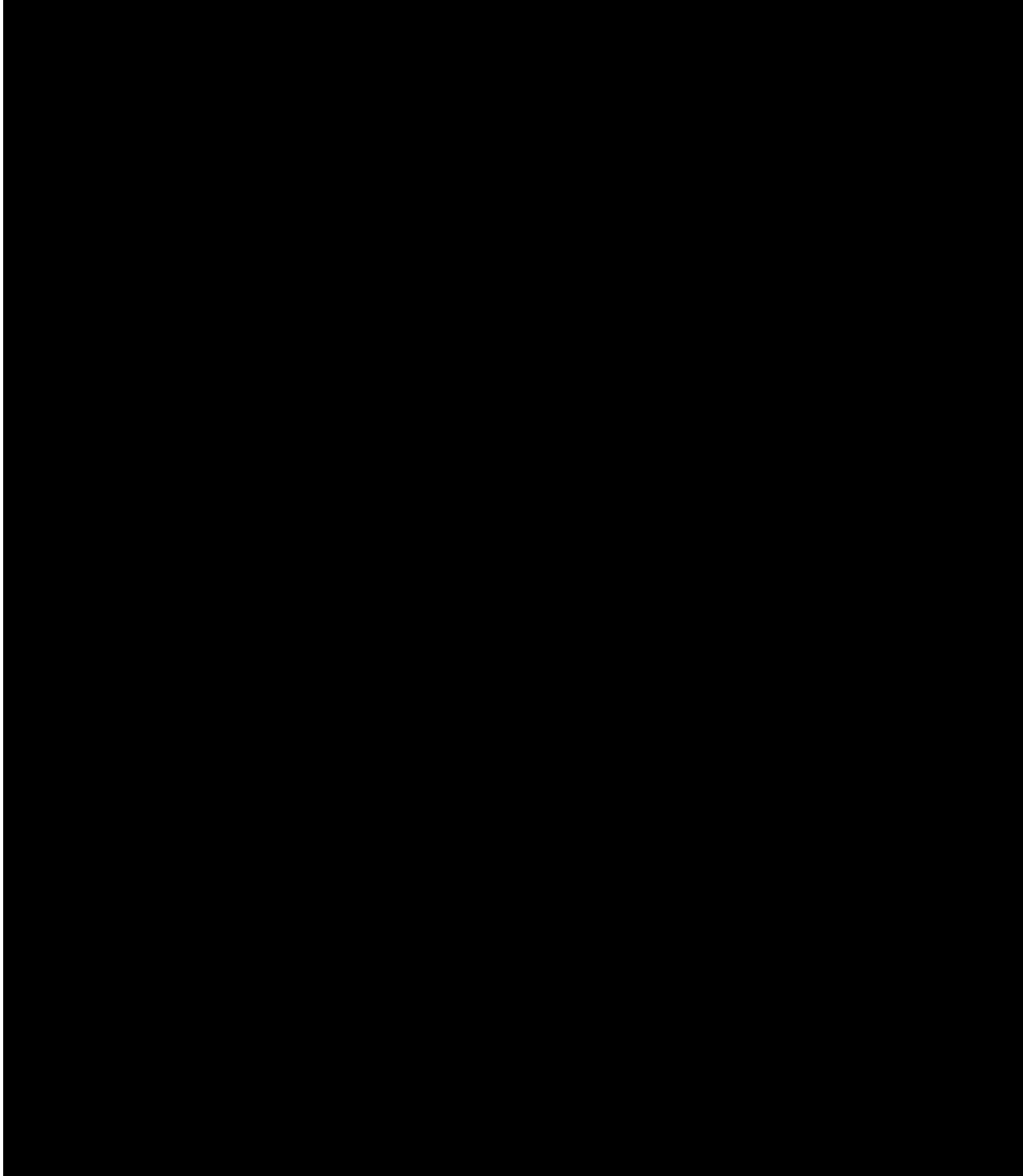


Claimed as PBI

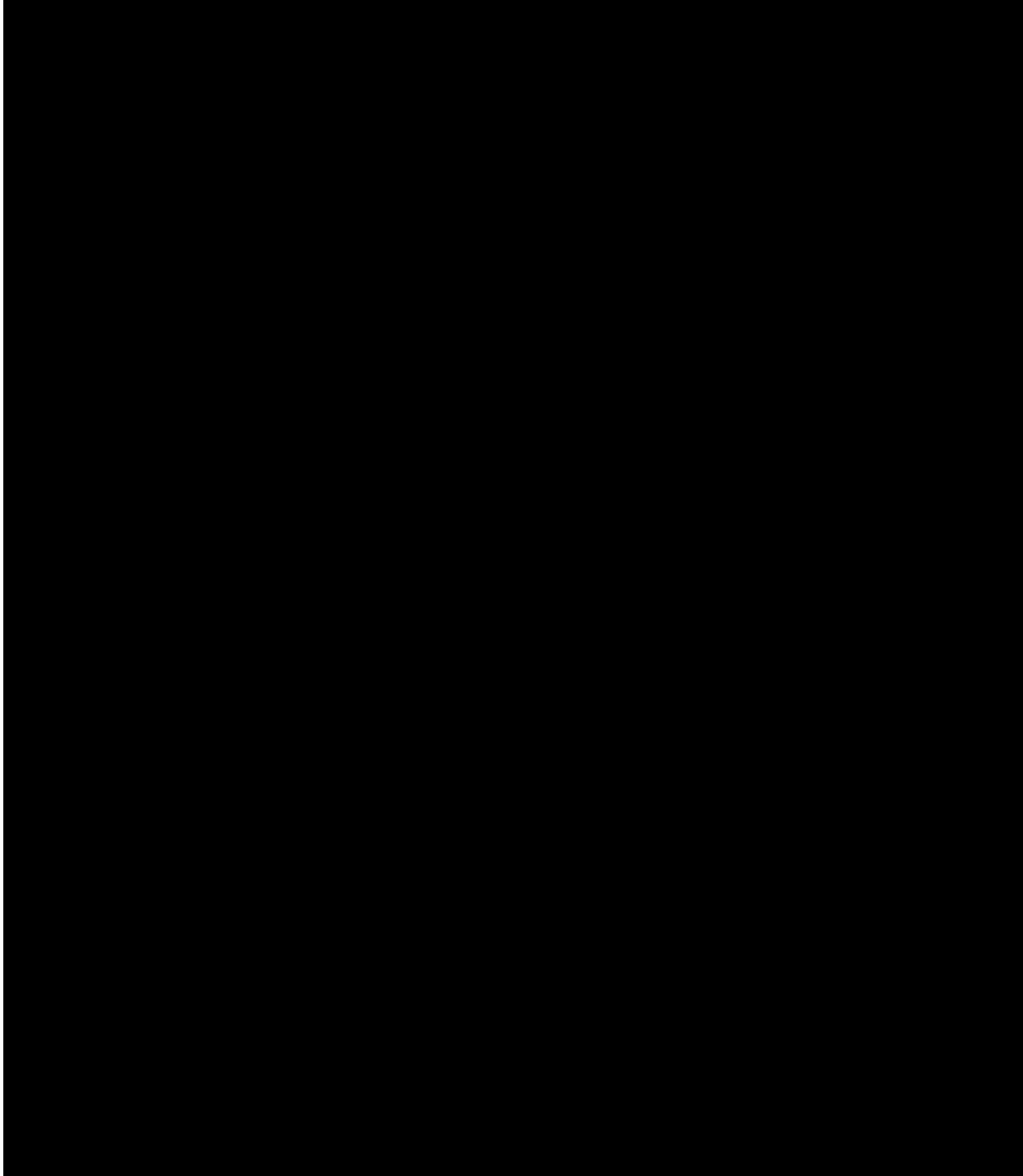
Claimed as PBI



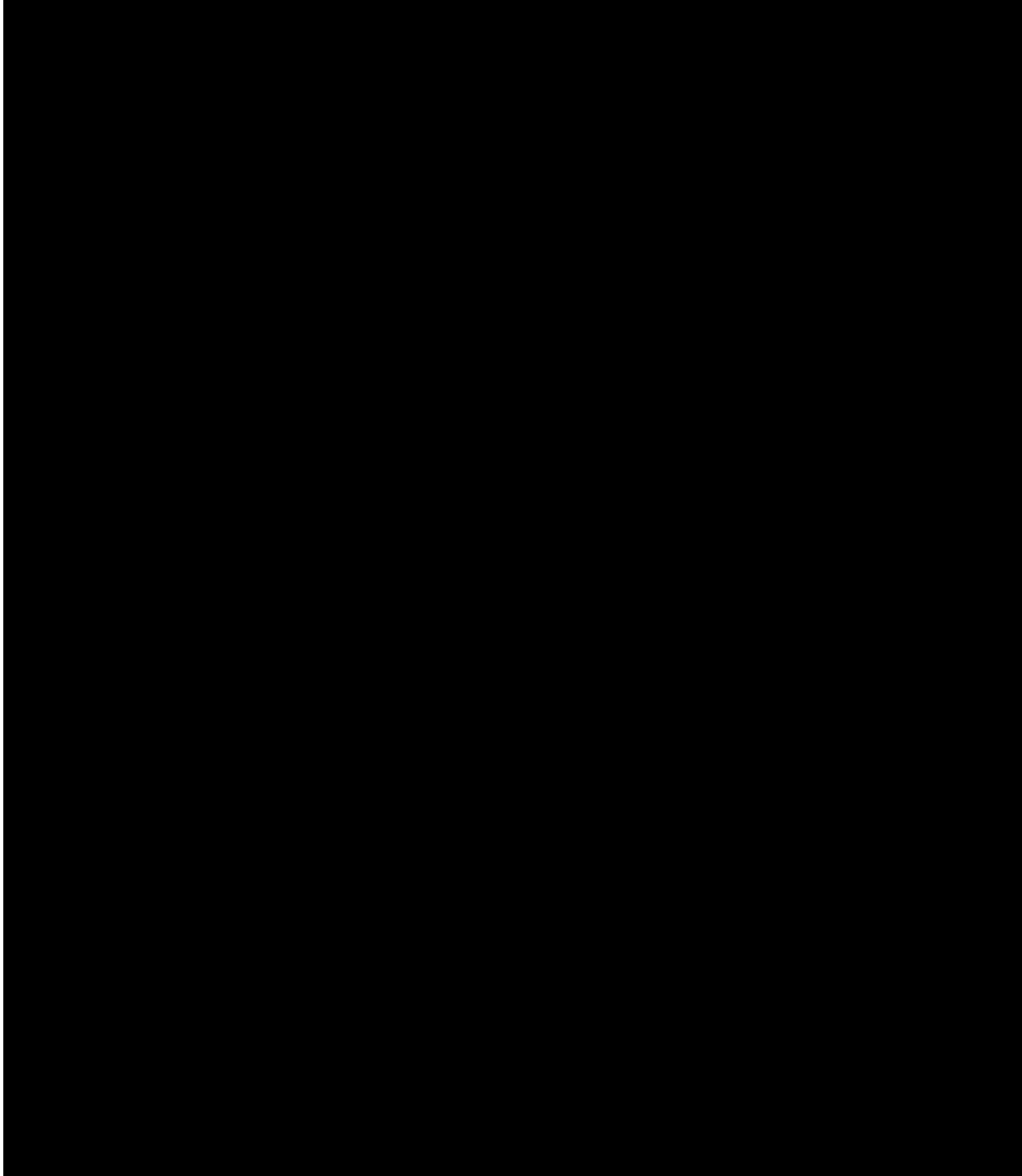
Claimed as PBI



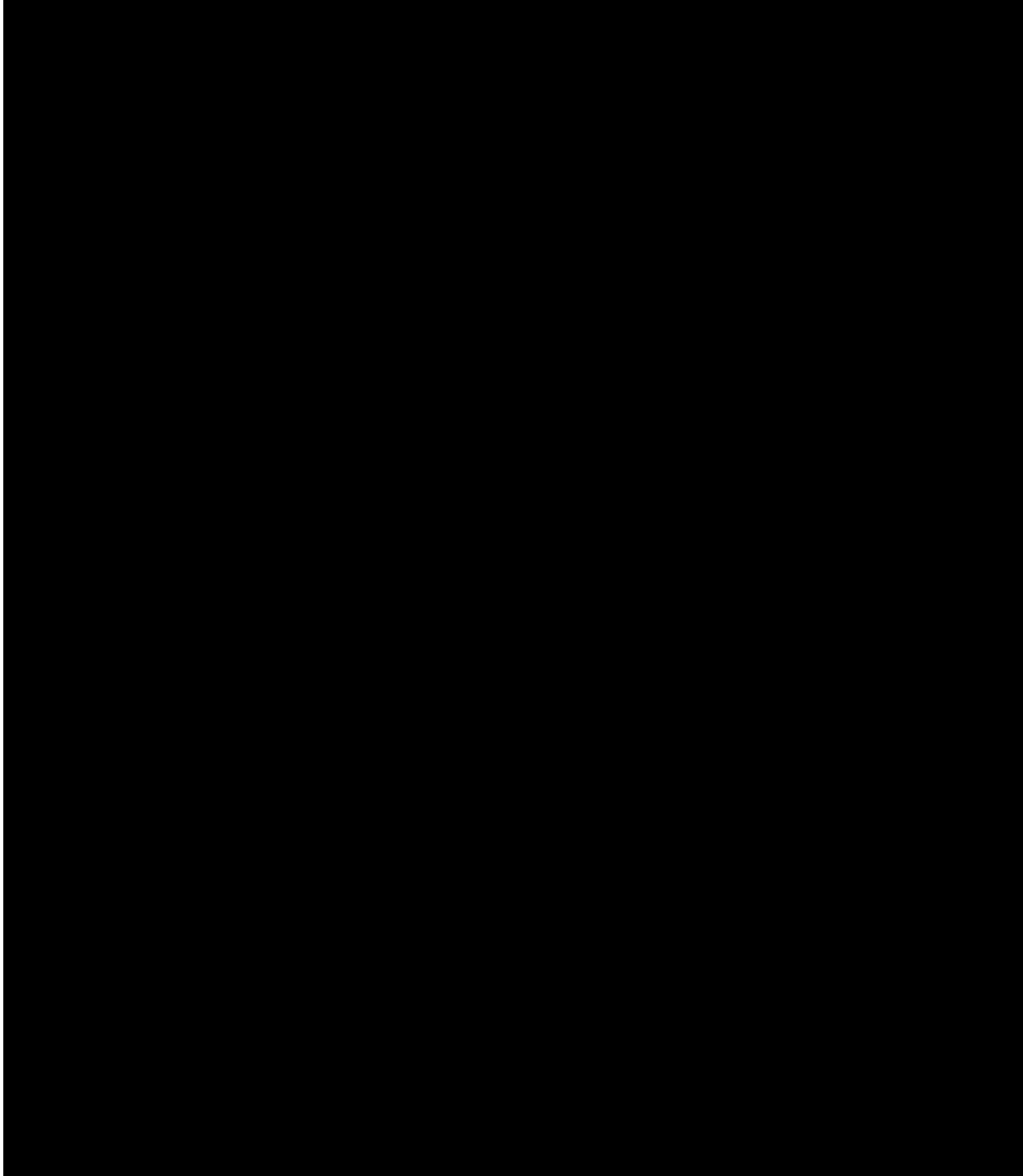
Claimed as PBI



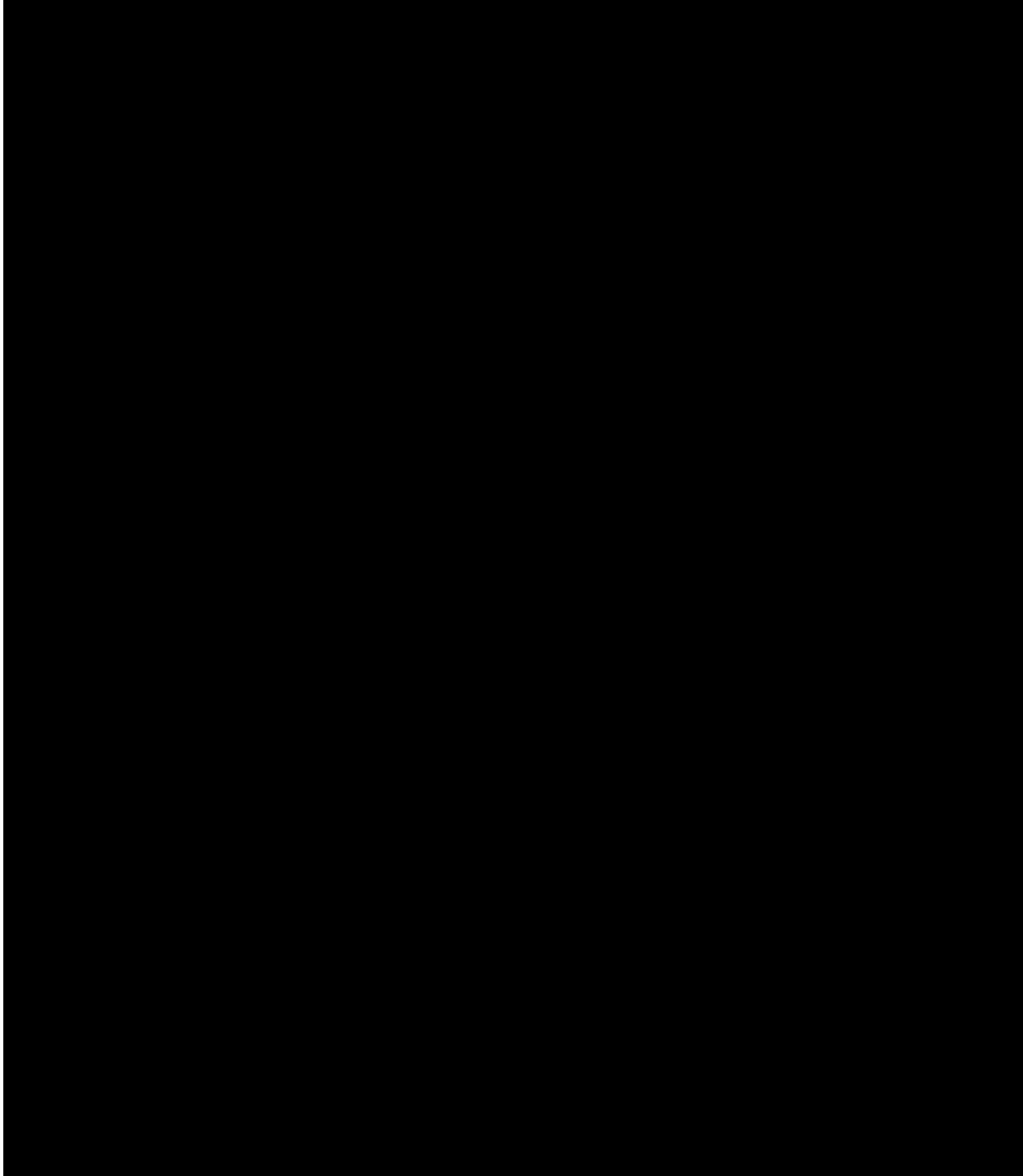
Claimed as PBI



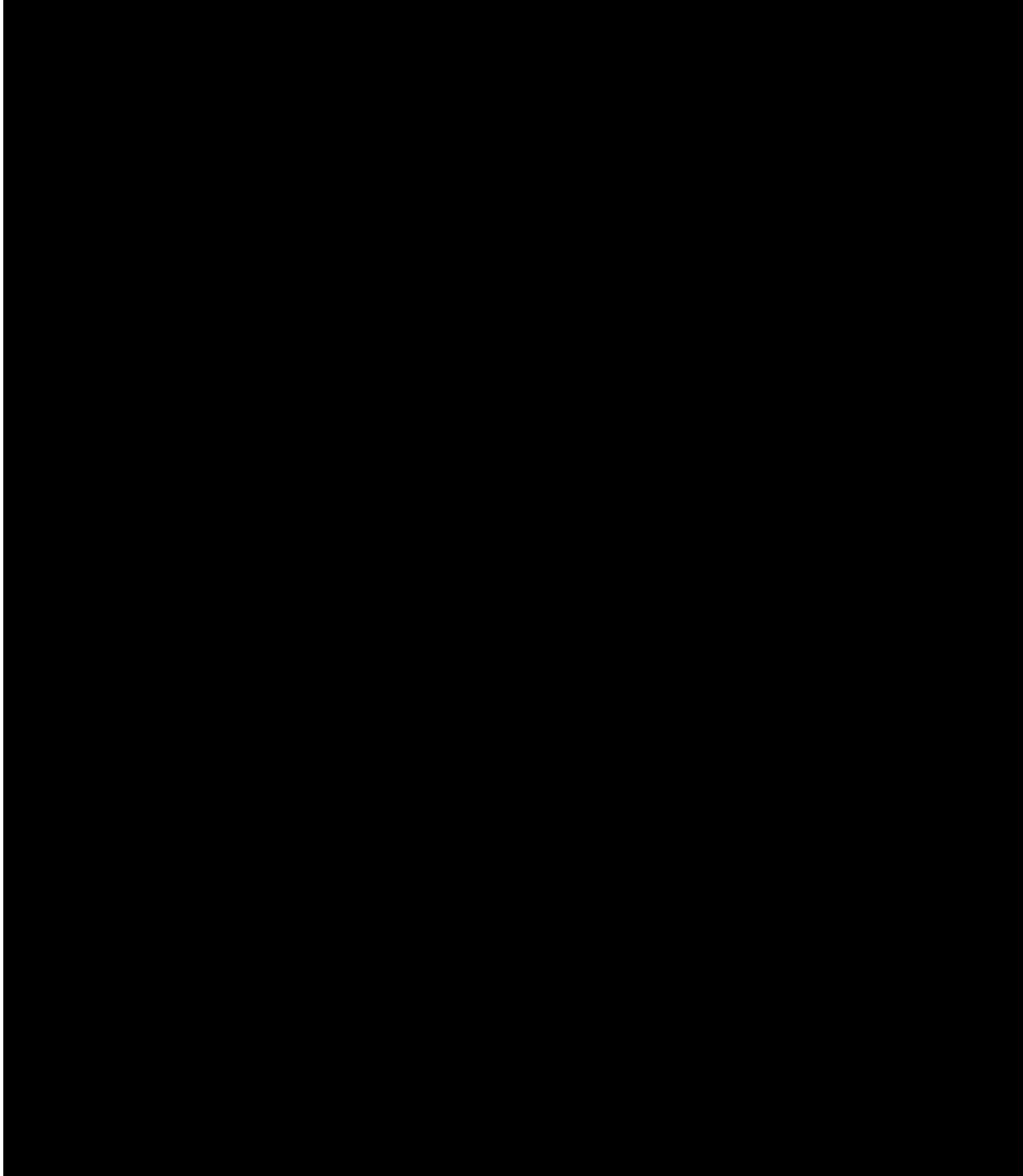
Claimed as PBI



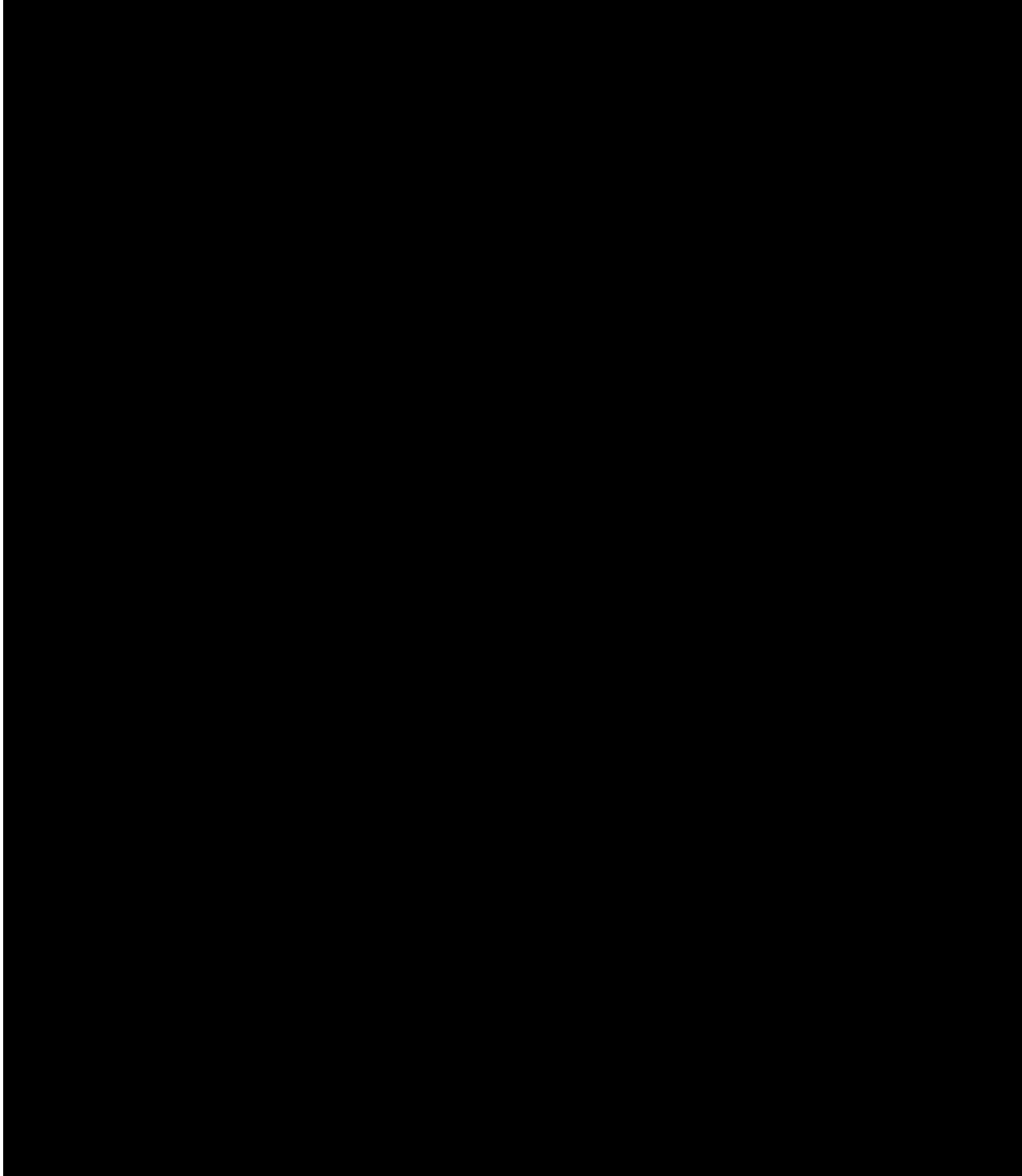
Claimed as PBI



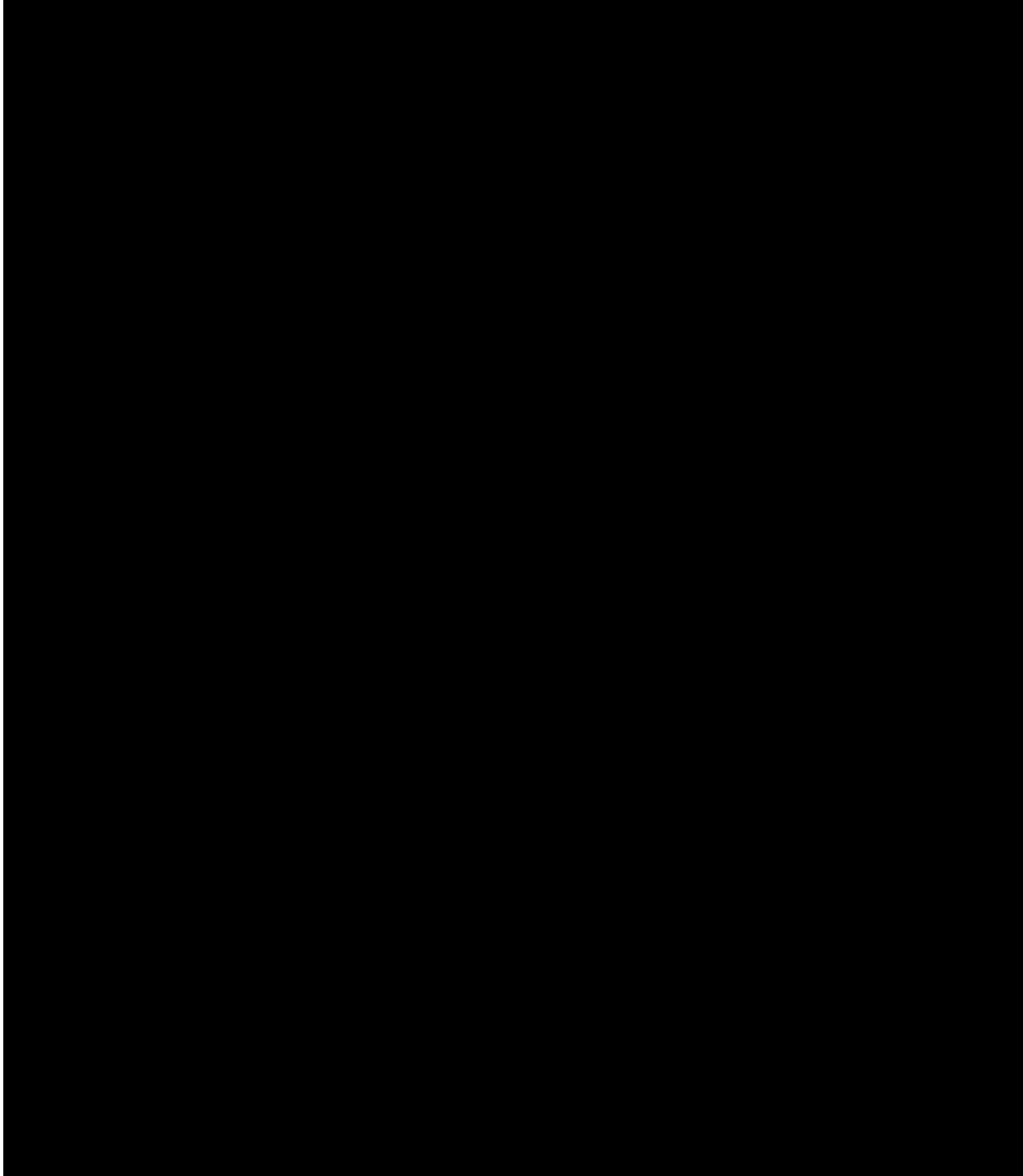
Claimed as PBI



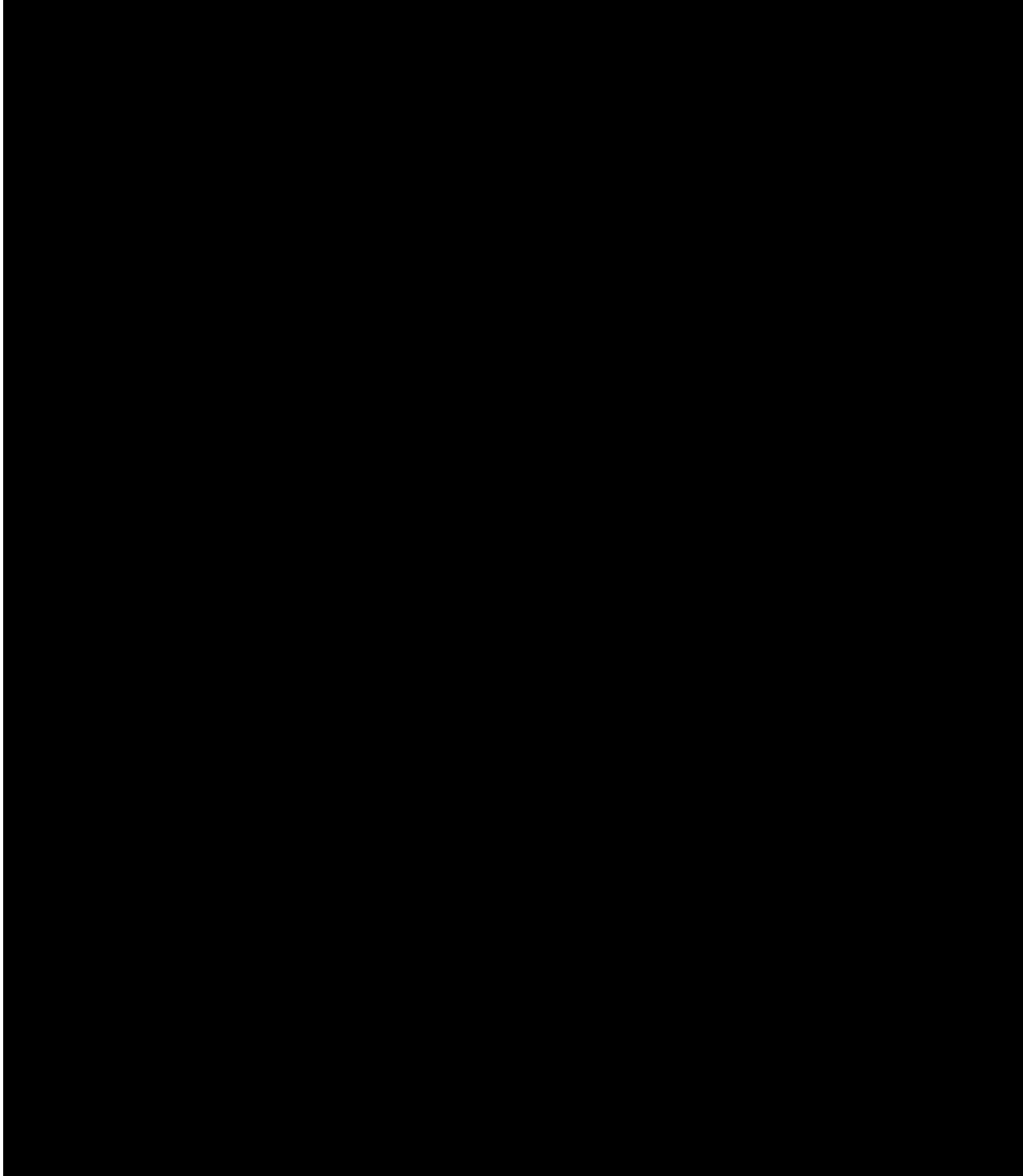
Claimed as PBI



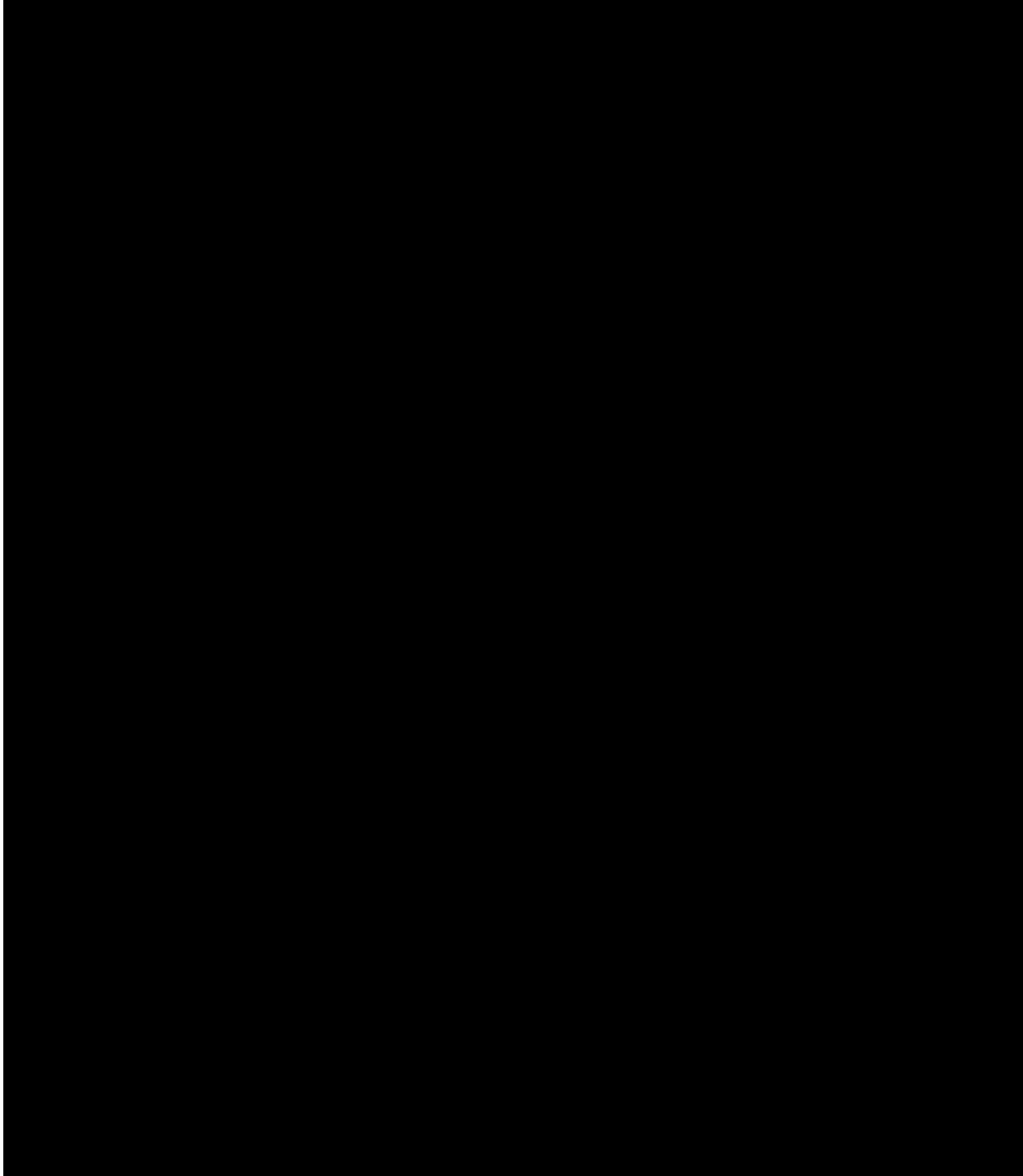
Claimed as PBI



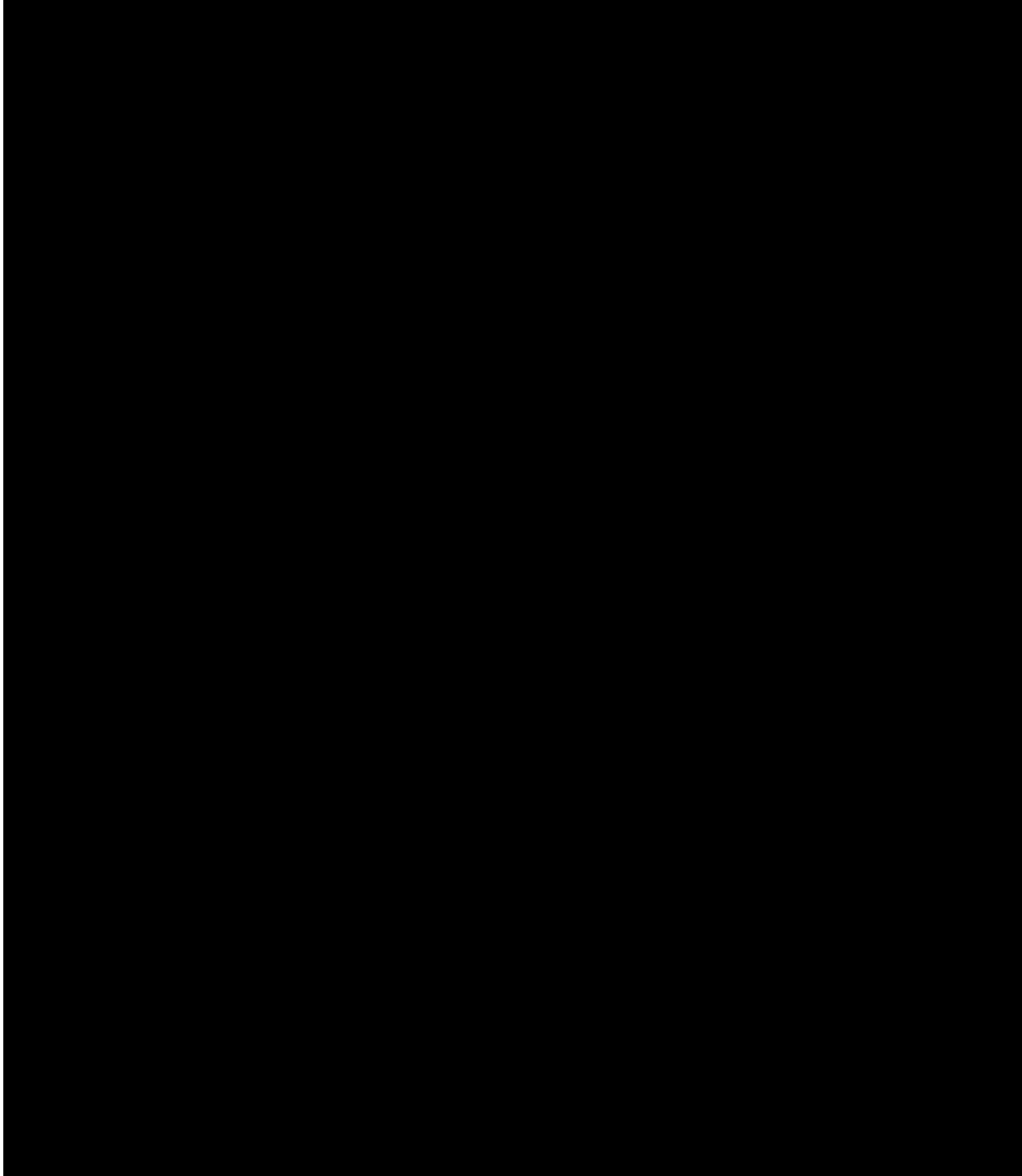
Claimed as PBI



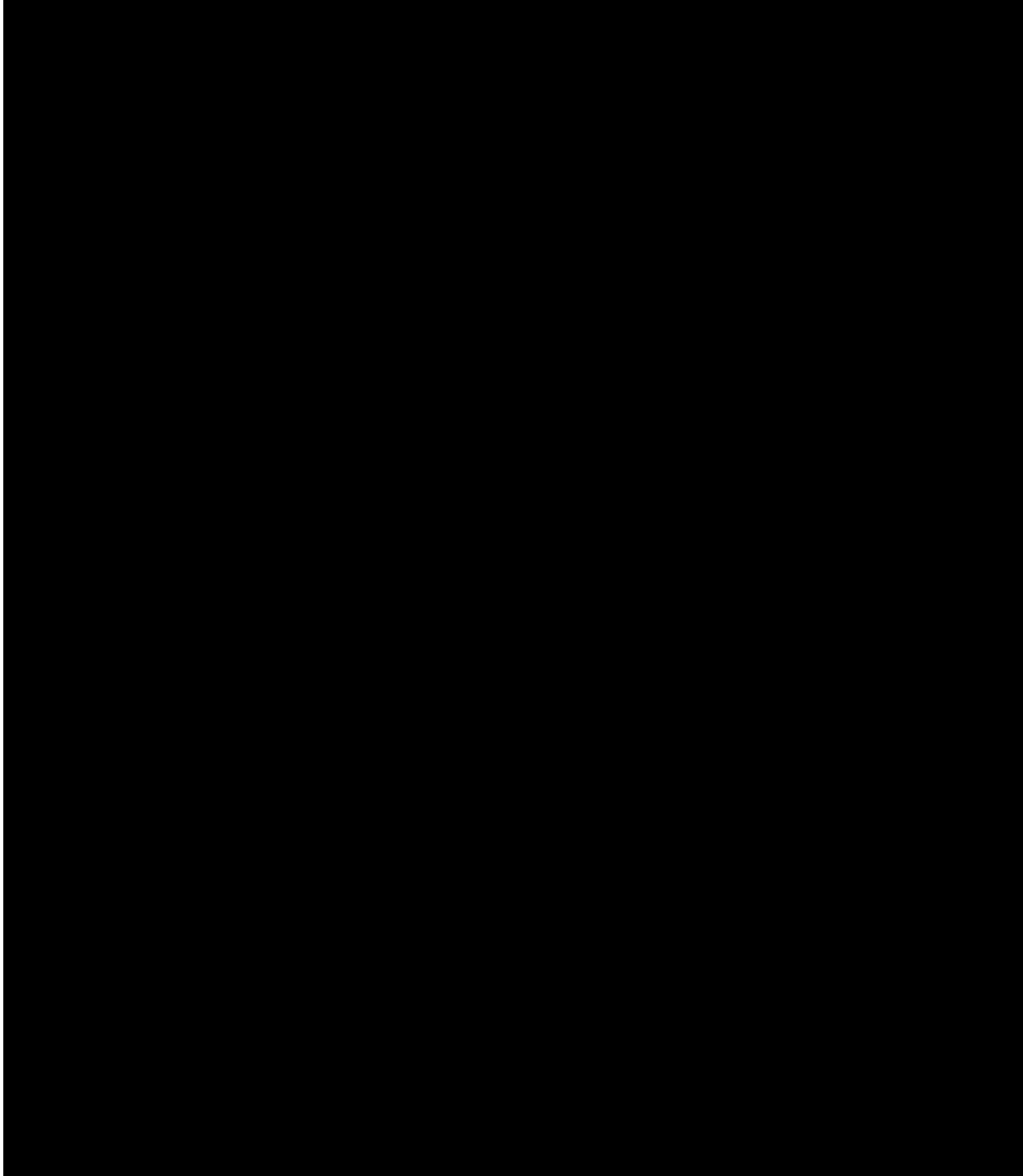
Claimed as PBI



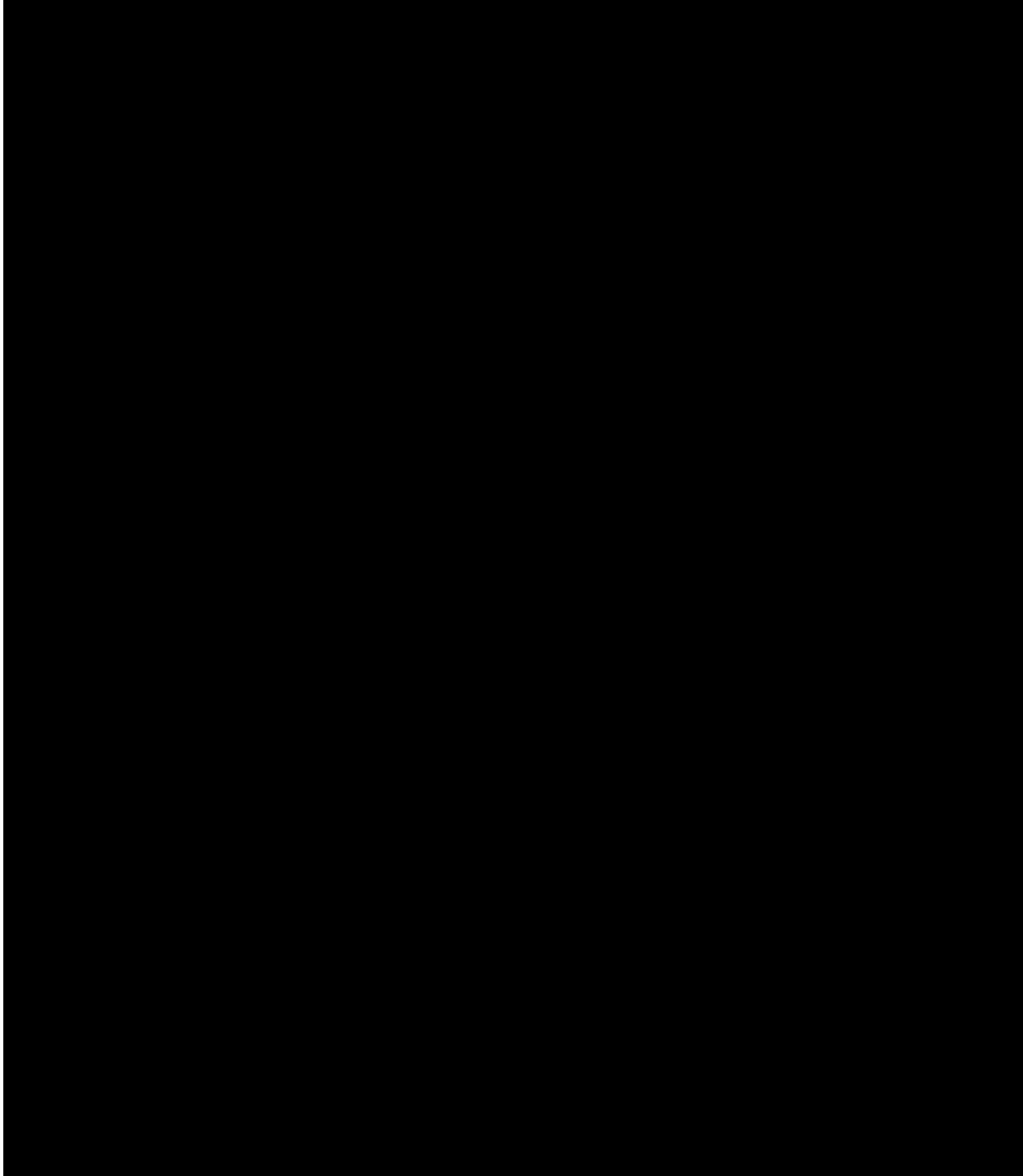
Claimed as PBI



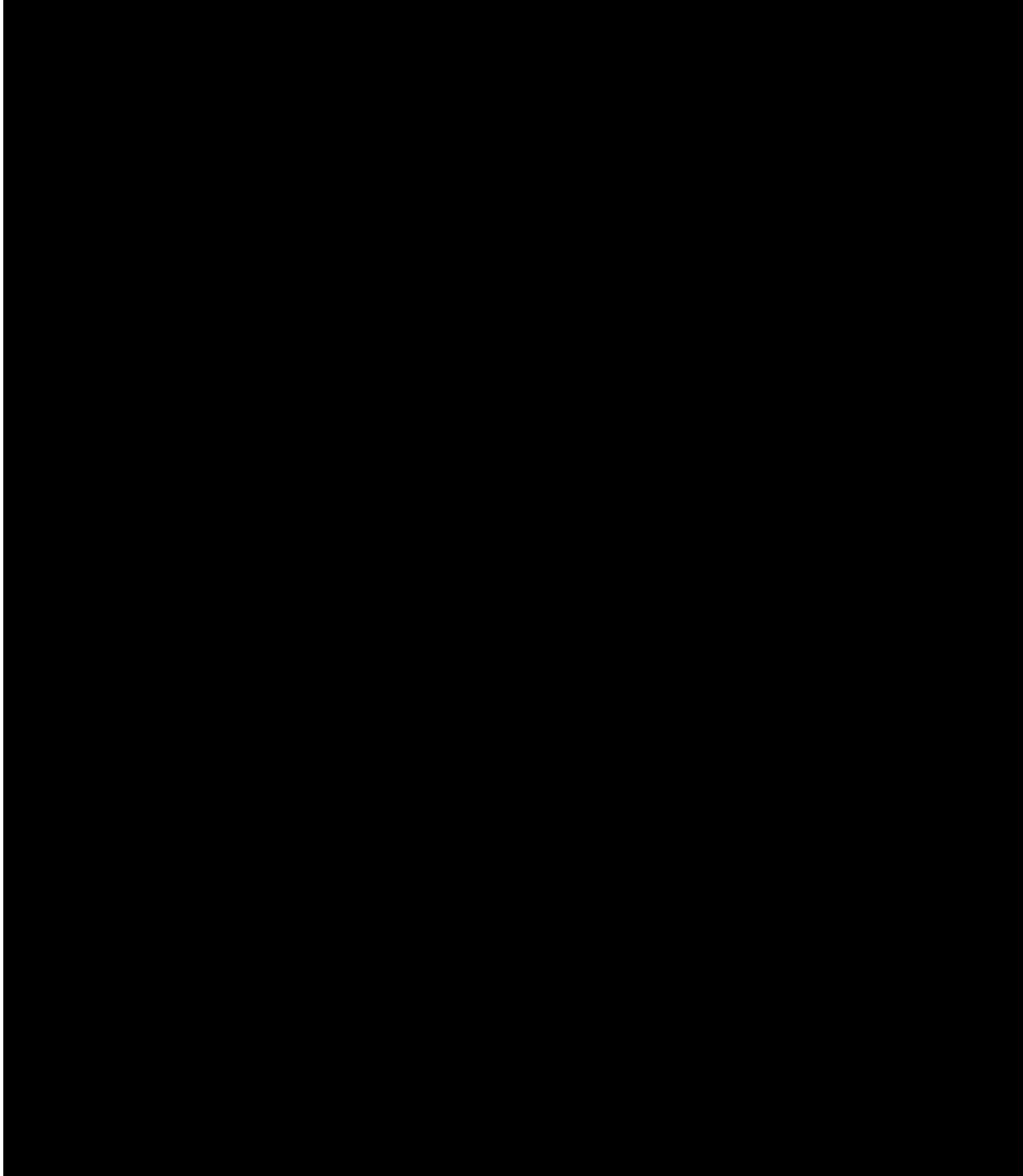
Claimed as PBI



Claimed as PBI



Claimed as PBI



Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

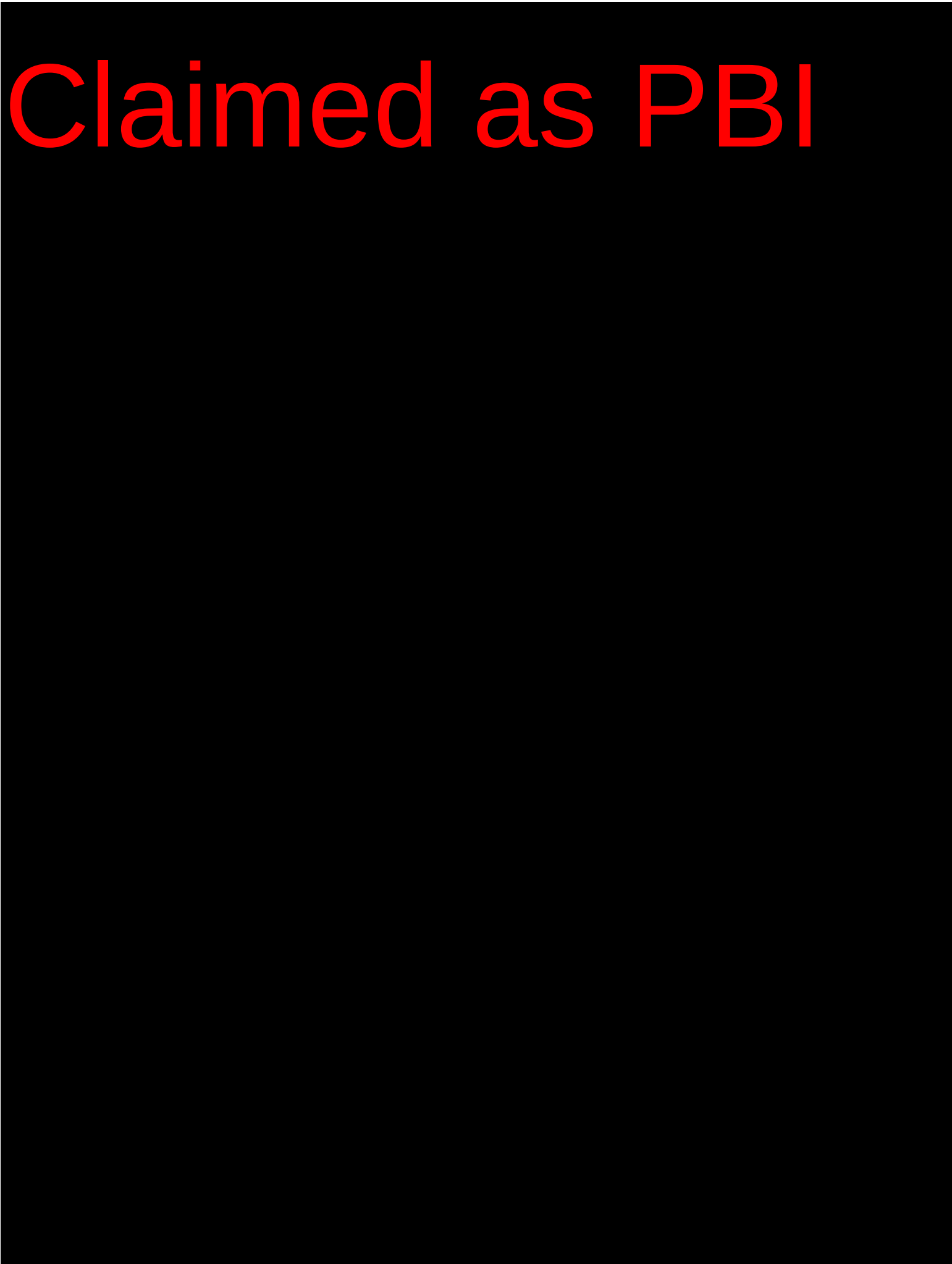
Claimed as PBI

Claimed as PBI

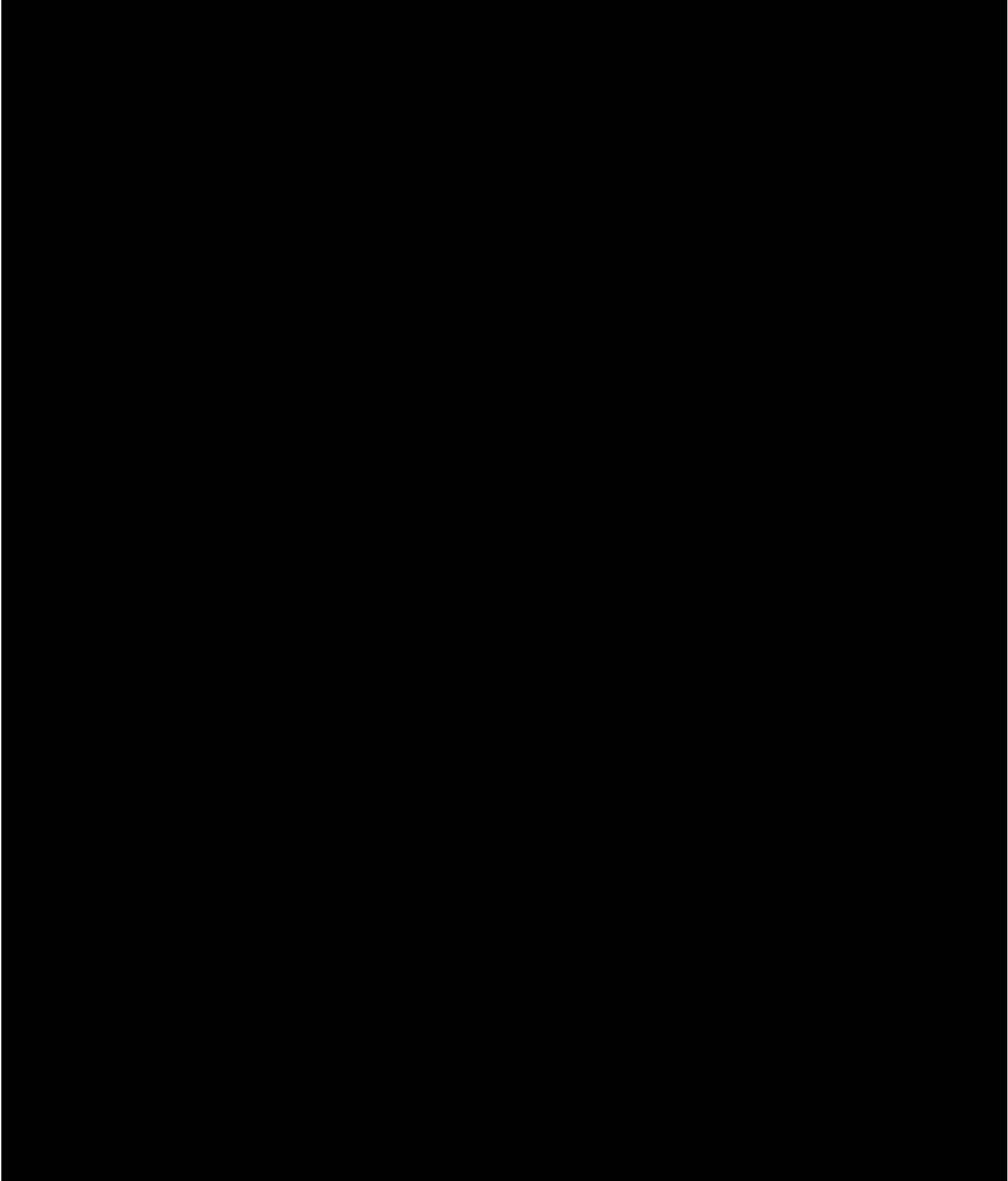
Claimed as PBI

Claimed as PBI

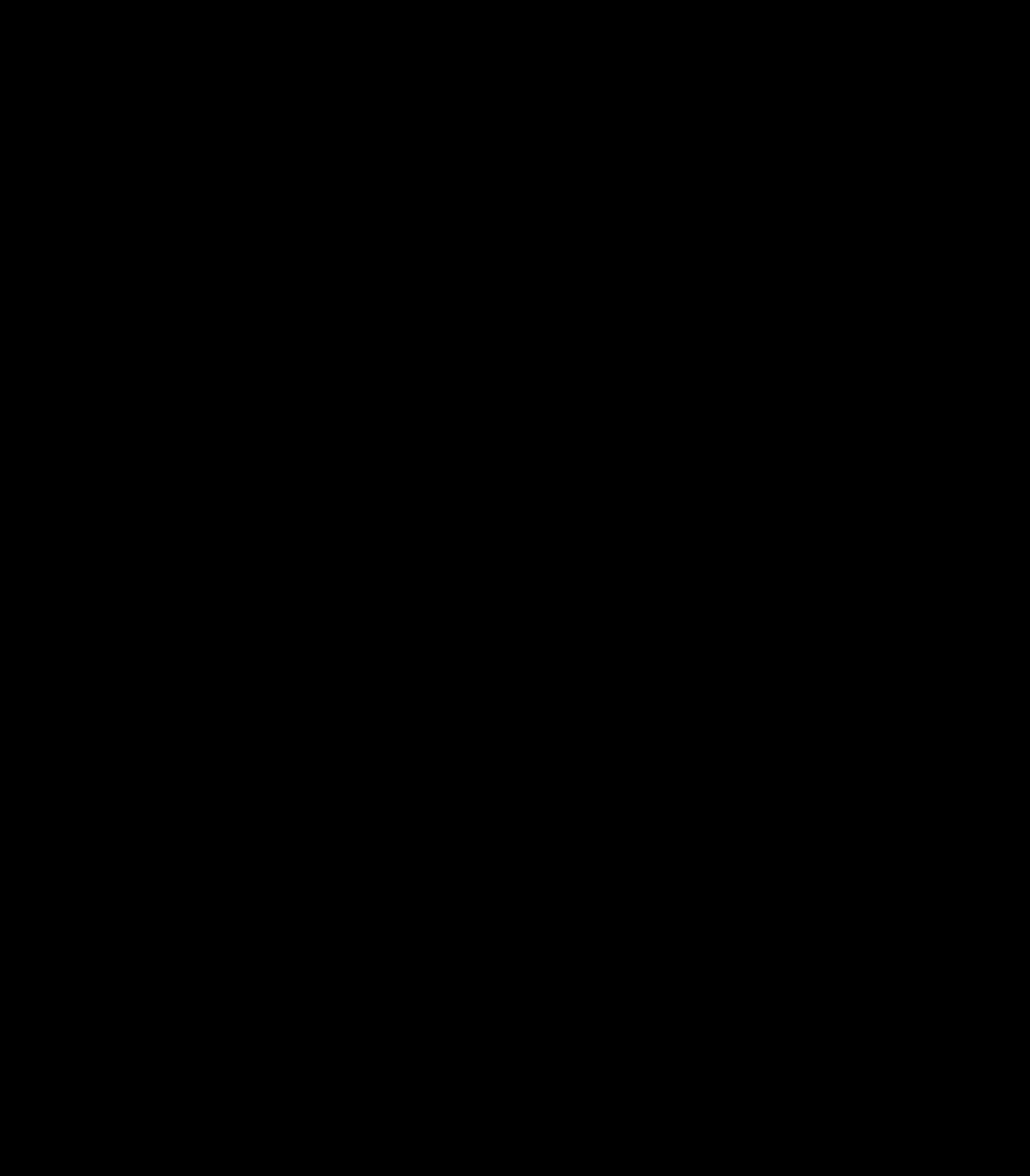
Claimed as PBI



Claimed as PBI



Claimed as PBI



CONFIDENTIAL BUSINESS INFORMATION

Claimed as PBI

CONFIDENTIAL BUSINESS INFORMATION

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

CONFIDENTIAL BUSINESS INFORMATION

-Page Intentionally Left Blank-

[REDACTED]
[REDACTED]
Claimed as PBI [REDACTED]
[REDACTED]

CONFIDENTIAL BUSINESS INFORMATION

-Page Intentionally Left Blank-

Claimed as PBI

Claimed as PBI

Claimed as PBI

CONFIDENTIAL BUSINESS INFORMATION

-Page Intentionally Left Blank-

Appendix L References

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

Claimed as PBI

CONFIDENTIAL BUSINESS INFORMATION

-Page Intentionally Left Blank-