IFRS® Sustainability

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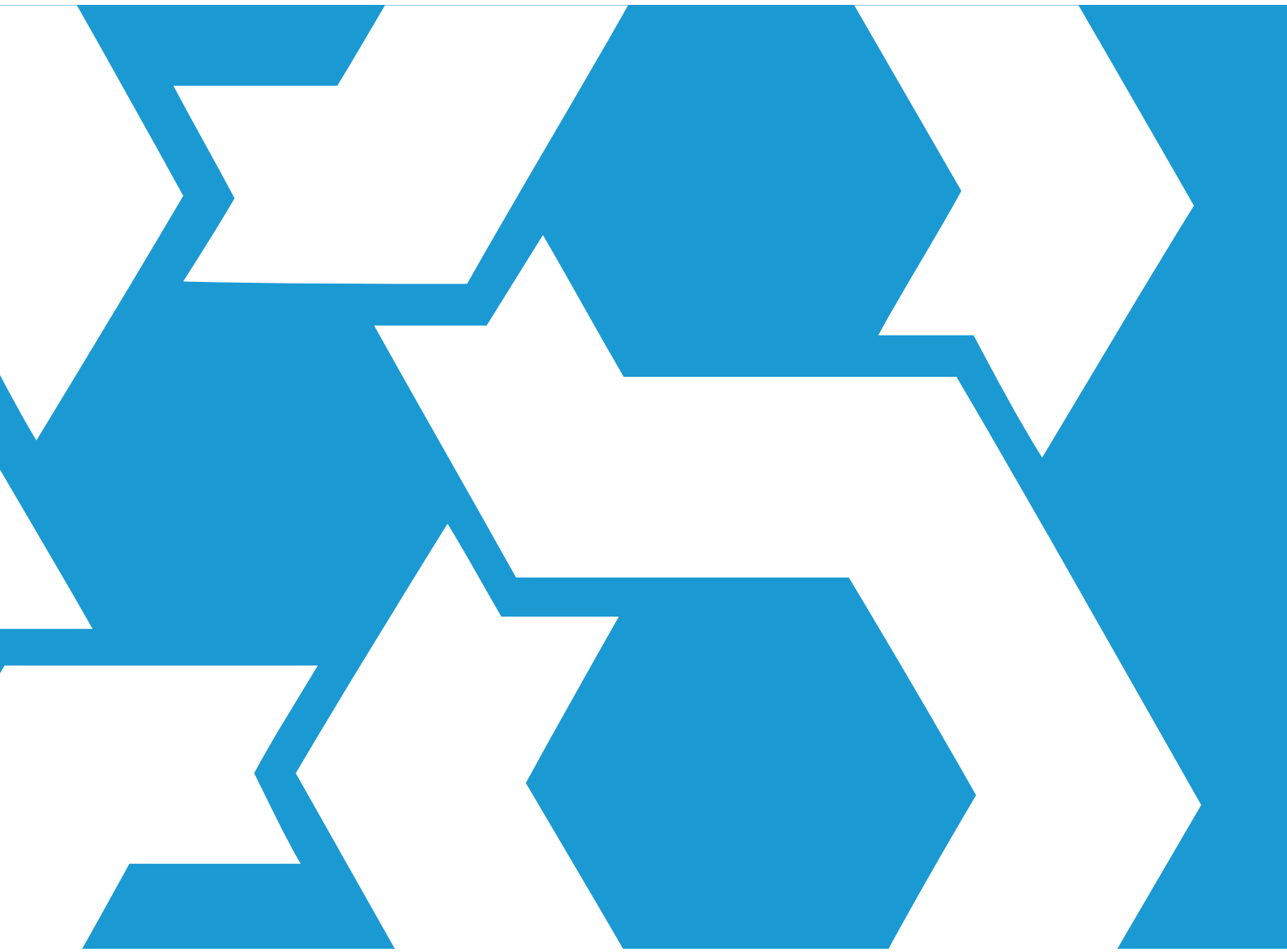
IFRS S2

IFRS® Sustainability Disclosure Standard

Industry-based Guidance on implementing Climate-related Disclosures

Volume 11—Oil & Gas – Exploration & Production



International Sustainability Standards Board

This Industry-based Guidance accompanies IFRS S2 *Climate related Disclosures* (published June 2023; see separate booklet) and is issued by the International Sustainability Standards Board (ISSB).

Introduction

This volume is part of the Industry-based Guidance on Implementing IFRS S2 Climate-related Disclosures. *This guidance suggests possible ways to apply some of the disclosure requirements in IFRS S2 but does not create additional requirements.*

This volume suggests possible ways to identify, measure and disclose information about climate-related risks and opportunities that are associated with particular business models, economic activities and other common features that characterise participation in this industry.

This industry-based guidance has been derived from Sustainability Accounting Standards Board (SASB) Standards, which are maintained by the International Sustainability Standards Board (ISSB). The metric codes used in SASB Standards have been included for ease of reference. For additional context regarding the industry-based guidance contained in this volume, including structure and terminology, application and illustrative examples, refer to Section III of the Accompanying Guidance to IFRS S2.

Volume 11—Oil & Gas – Exploration & Production

Industry Description

Oil & Gas - Exploration & Production (E&P) entities explore for, extract or produce energy products such as crude oil and natural gas, which comprise the upstream operations of the oil and gas value chain. Entities in the industry develop conventional and unconventional oil and gas reserves; these include shale oil or gas reserves, oil sands and gas hydrates. Activities covered by this standard include the development of both on-shore and off-shore reserves. The E&P industry creates contracts with the Oil and Gas Services industry to conduct several E&P activities and to obtain equipment and oilfield services.

Note: These discolosure topics are for 'pure-play' E&P activities or independent E&P entities. Integrated oil and gas entities conduct upstream operations but also may distribute, refine or market crude oil, natural gas or refined products. Separate standards exist for the Oil and Gas Midstream (EM-MD) and Refining & Marketing (EM-RM) industries. As such, integrated entities should also consider the disclosure topics and metrics from these Standards. A separate standard also exists for the Oil and Gas Services industry (EM-SV).

Sustainability Disclosure Topics & Metrics

Table 1. Sustainability Disclosure Topics & Metrics

TOPIC	METRIC	CATEGORY	UNIT OF MEASURE	CODE
Greenhouse Gas Emissions	Gross global Scope 1 emissions, percentage methane, percentage covered under emissions-limiting regulations	Quantitative	Metric tons CO_2-e (t), Percentage (%)	EM-EP-110a.1
	Amount of gross global Scope 1 emissions from: (1) flared hydrocarbons, (2) other combustion, (3) process emissions, (4) other vented emissions and (5) fugitive emissions	Quantitative	Metric tons CO_2-e	EM-EP-110a.2
	Discussion of long- and short-term strategy or plan to manage Scope 1 emissions, emissions reduction targets, and an analysis of performance against those targets	Discussion and Analysis	n/a	EM-EP-110a.3

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TOPIC	METRIC	CATEGORY	UNIT OF MEASURE	CODE
Water Management	(1) Total water withdrawn, (2) total water consumed; percentage of each in regions with High or Extremely High Baseline Water Stress	Quantitative	Thousand cubic metres (m^3), Percentage (%)	EM-EP-140a.1
	Volume of produced water and flowback generated; percentage (1) discharged, (2) injected, (3) recycled; hydrocarbon content in discharged water	Quantitative	Thousand cubic metres (m^3), Percentage (%), Metric tons (t)	EM-EP-140a.2
	Percentage of hydraulically fractured wells for which there is public disclosure of all fracturing fluid chemicals used	Quantitative	Percentage (%)	EM-EP-140a.3
	Percentage of hydraulic fracturing sites where ground or surface water quality deteriorated compared to a baseline [12]	Quantitative	Percentage (%)	EM-EP-140a.4
Reserves Valuation & Capital Expenditures	Sensitivity of hydrocarbon reserve levels to future price projection scenarios that account for a price on carbon emissions	Quantitative	Million barrels (MMbbls), Million standard cubic feet (MMscf)	EM-EP-420a.1
	Estimated carbon dioxide emissions embedded in proved hydrocarbon reserves	Quantitative	Metric tons (t) CO_2-e	EM-EP-420a.2
	Amount invested in renewable energy, revenue generated by renewable energy sales	Quantitative	Presentation currency	EM-EP-420a.3
	Discussion of how price and demand for hydrocarbons or climate regulation influence the capital expenditure strategy for exploration, acquisition and development of assets	Discussion and Analysis	n/a	EM-EP-420a.4

Table 2. Activity Metrics

ACTIVITY METRIC	CATEGORY	UNIT OF MEASURE	CODE
Production of: (1) oil, (2) natural gas, (3) synthetic oil, and (4) synthetic gas	Quantitative	Thousand barrels per day (Mbbl/day); Million standard cubic feet per day (MMscf/day)	EM-EP-000.A

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[12] Note to **EM-EP-140a.4** – The entity shall disclose its policies and practices related to ground and surface water quality management.

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ACTIVITY METRIC	CATEGORY	UNIT OF MEASURE	CODE
Number of offshore sites	Quantitative	Number	EM-EP-000.B
Number of terrestrial sites	Quantitative	Number	EM-EP-000.C

Greenhouse Gas Emissions

Topic Summary

Exploration & Production (E&P) activities generate significant direct greenhouse gas (GHG) emissions from a variety of sources. Emissions may be combusted, including those arising from flaring or power generation equipment, or uncombusted, including those emissions arising from gas processing equipment, venting, flaring and fugitive methane. Regulatory efforts to reduce GHG emissions in response to climate change related risks may result in additional regulatory compliance costs and risks for E&P entities. With natural gas production from shale resources expanding, the management of the emission of methane, a highly potent GHG, from oil and gas E&P systems has emerged as a major operational, reputational and regulatory risk for entities. Furthermore, the development of unconventional hydrocarbon resources may be more or less GHG-intensive than conventional oil and gas, with associated effects on regulatory risk. Energy efficiency, use of less carbon-intensive fuels, or process improvements to reduce fugitive emissions, venting and flaring, can provide direct benefits to E&P entities in the form of reduced costs or increased revenue.

Metrics

EM-EP-110a.1. Gross global Scope 1 emissions, percentage methane, percentage covered under emissions-limiting regulations

1 The entity shall disclose its gross global Scope 1 greenhouse gas (GHG) emissions to the atmosphere of the seven GHGs covered under the Kyoto Protocol—carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6), and nitrogen trifluoride (NF_3).

1.1 Emissions of all GHGs shall be consolidated and disclosed in metric tons of carbon dioxide equivalent (CO_2-e) and calculated in accordance with published 100-year time horizon global warming potential (GWP) values. To date, the preferred source for GWP values is the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (2014).

1.2 Gross emissions are GHGs emitted into the atmosphere before accounting for offsets, credits or other similar mechanisms that have reduced or compensated for emissions.

2 Scope 1 emissions are defined and shall be calculated according to the methodology contained in *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard* (GHG Protocol), Revised Edition, March 2004, published by the World Resources Institute and the World Business Council on Sustainable Development (WRI/WBCSD).

2.1 These emissions include direct emissions of GHGs from stationary or mobile sources; these sources may include: equipment at well sites, production facilities, refineries, chemical plants, terminals, fixed site drilling rigs, office buildings, marine vessels transporting products, tank truck fleets, mobile drilling rigs, and moveable equipment at drilling and production facilities.

2.2 Acceptable calculation methodologies include those that conform to the GHG Protocol as the base reference, but provide additional guidance, such as industry- or region-specific guidance. Examples include:

2.2.1 *GHG Reporting Guidance for the Aerospace Industry* published by the International Aerospace Environmental Group (IAEG)

2.2.2 *Greenhouse Gas Inventory Guidance: Direct Emissions from Stationary Combustion Sources* published by the U.S. Environmental Protection Agency (EPA)

2.2.3 India GHG Inventory Program

2.2.4 ISO 14064-1

2.2.5 *Petroleum Industry Guidelines for reporting GHG emissions*, 2nd edition, 2011, published by IPIECA

2.2.6 *Protocol for the quantification of greenhouse gas emissions from waste management activities* published by Entreprises pour l'Environnement (EpE)

2.3 GHG emission data shall be consolidated according to the approach with which the entity consolidates its financial reporting data, which is generally aligned with the 'financial control' approach defined by the GHG Protocol as well as:

2.3.1 The financial approach detailed in Chapter 3 of the IPIECA/API/OGP *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions*, 2nd Edition, 2011 (hereafter, the 'IPIECA GHG Guidelines')

2.3.2 The approach provided by the Climate Disclosure Standards Board (CDSB) that is described in REQ-07, 'Organisational boundary,' of the *CDSB Framework for reporting environmental and social information*

3 The entity shall disclose the percentage of gross global Scope 1 emissions from methane emissions.

3.1 The percentage of gross global Scope 1 GHG emissions from methane emissions shall be calculated as the methane emissions in metric tons of carbon dioxide equivalents (CO_2-e) divided by the gross global Scope 1 GHG emissions in metric tons of carbon dioxide equivalents (CO_2-e).

4 The entity shall disclose the percentage of its gross global Scope 1 GHG emissions covered under an emissions-limiting regulation or programme intended to limit or reduce emissions directly, such as cap-and-trade schemes, carbon tax/fee systems, and other emissions control (for example, command-and-control approach) and permit-based mechanisms.

4.1 Examples of emissions-limiting regulations include:

4.1.1 California Cap-and-Trade (California Global Warming Solutions Act)

4.1.2 European Union Emissions Trading Scheme (EU ETS)

4.1.3 Quebec Cap-and-Trade (Quebec Environment Quality Act)

4.2 The percentage shall be calculated as the total amount of gross global Scope 1 GHG emissions (CO_2-e) covered under emissions-limiting regulations divided by the total amount of gross global Scope 1 GHG emissions (CO_2-e).

4.2.1 For emissions subject to more than one emissions-limiting regulation, the entity shall not account for those emissions more than once.

4.3 The scope of emissions-limiting regulations excludes emissions covered under voluntary emissions-limiting regulations (for example, voluntary trading systems), as well as reporting-based regulations.

5 The entity may discuss any change in its emissions from the previous reporting period, including whether the change was because of emissions reductions, divestment, acquisition, mergers, changes in output or changes in calculation methodology.

6 In the case that current reporting of GHG emissions to the CDP or other entity (for example, a national regulatory disclosure programme) differs in terms of the scope and consolidation approach used, the entity may disclose those emissions. However, primary disclosure shall be according to the guidelines described above.

7 The entity may discuss the calculation methodology for its emissions disclosure, such as if data are from continuous emissions monitoring systems (CEMS), engineering calculations or mass balance calculations.

EM-EP-110a.2. Amount of gross global Scope 1 emissions from: (1) flared hydrocarbons, (2) other combustion, (3) process emissions, (4) other vented emissions and (5) fugitive emissions

1 The entity shall disclose the amount of direct greenhouse gas (GHG) emissions in CO_2-e from the following sources (1) flared hydrocarbons, (2) other combustion, (3) process emissions, (4) other vented emissions and (5) fugitive emissions from operations.

1.1 Flared hydrocarbons shall include all emissions emitted from flares and which are associated with the management and disposal of unrecoverable natural gas via combustion of hydrocarbon products from routine operations, upsets or emergencies.

1.2 Other combusted emissions shall include:

1.2.1 Emissions from stationary devices, which may include boilers, heaters, furnaces, reciprocating internal combustion engines and turbines, incinerators, and thermal/catalytic oxidisers

1.2.2 Emissions from mobile sources, which may include barges, ships, railcars and trucks for material transport; planes/helicopters and other entity vehicles for personnel transport; forklifts, all-terrain vehicles, construction equipment and other off-road mobile equipment

1.3 Other combusted emissions shall exclude those emissions disclosed as flared hydrocarbons.

1.4 Process emissions shall include those emissions that are not combusted and are intentional or designed into the process or technology to occur during normal operations and are a result of some form of chemical transformation or processing step. Such emissions may include emissions from hydrogen plants, amine units, glycol dehydrators, fluid catalytic cracking unit and reformer generation, and flexi-coker coke burn.

1.5 Vented emissions shall include those emissions that are not combusted and are intentional or designed into the process or technology to occur during normal operations, and which include:

1.5.1 Venting from crude oil, condensate or natural gas product storage tanks, gas-driven pneumatic devices, gas samplers, chemical injection pumps, exploratory drilling, loading/ballasting/transit and loading racks

1.5.2 Venting resulting from maintenance/turn-arounds, which may include decoking of furnace tubes, well unloading, vessel and gas compressor depressurising, compressor starts, gas sampling, and pipeline blowdowns

1.5.3 Venting from non-routine activities, which may include pressure relief valves, pressure control valves, fuel supply unloading valves and emergency shut-down devices

1.6 Vented emissions shall exclude those emissions disclosed as process emissions.

1.7 Fugitive emissions shall include those emissions that can be individually found and fixed to reduce emissions rates to near zero and which may include emissions from valves, flanges, connectors, pumps, compressor seal leaks, Cata-Dyne® heaters, and wastewater treatment and surface impoundments.

EM-EP-110a.3. Discussion of long- and short-term strategy or plan to manage Scope 1 emissions, emissions reduction targets, and an analysis of performance against those targets

1 The entity shall discuss its long- and short-term strategy or plan to manage its Scope 1 greenhouse gas (GHG) emissions.

1.1 Scope 1 emissions are defined and shall be calculated according to the methodology contained in *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard* (GHG Protocol), Revised Edition, March 2004, published by the World Resources Institute and the World Business Council on Sustainable Development (WRI/WBCSD).

1.2 The scope of GHG emissions includes the seven GHGs covered under the Kyoto Protocol—carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulphur hexafluoride (SF_6), and nitrogen trifluoride (NF_3).

2 The entity shall discuss its emission reduction target(s) and analyse its performance against the target(s), including, if relevant:

2.1 The scope of the emission reduction target (for example, the percentage of total emissions to which the target is applicable);

2.2 Whether the target is absolute or intensity-based, and the metric denominator if it is an intensity-based target;

2.3 The percentage reduction against the base year, with the base year representing the first year against which emissions are evaluated towards the achievement of the target;

2.4 The time lines for the reduction activity, including the start year, the target year and the base year;

2.5 The mechanism(s) for achieving the target; and

2.6 Any circumstances in which the target or base year emissions have been, or may be, recalculated retrospectively, or the target or base year has been reset, which may include energy efficiency efforts, energy source diversification, carbon capture and storage, or the implementation of leak detection and repair processes.

3 The entity shall discuss the activities and investments required to achieve the plans or targets, and any risks or limiting factors that might affect achievement of the plans or targets.

4 The entity shall discuss the scope of its strategies, plans or reduction targets, such as whether they pertain differently to different business units, geographies or emissions sources.

4.1 Categories of emissions sources include:

4.1.1 Flared hydrocarbons, including all emissions emitted from flares and which are associated with the management and disposal of unrecoverable natural gas via combustion of hydrocarbon products from routine operations, upsets or emergencies

4.1.2 Other combusted emissions, which may include: (1) emissions from stationary devices, which may include boilers, heaters, furnaces, reciprocating internal combustion engines and turbines, incinerators, and thermal/catalytic oxidisers, (2) emissions from mobile sources, which may include barges, ships, railcars and

trucks for material transport; planes/helicopters and other entity vehicles for staff transport; forklifts, all-terrain vehicles, construction equipment and other off-road mobile equipment, and (3) other combusted emissions shall exclude those emissions disclosed as flared hydrocarbons

4.1.3 Process emissions, which include those emissions that are not combusted and are intentional or designed into the process or technology to occur during normal operations and are a result of some form of chemical transformation or processing step. Such emissions may include those from hydrogen plants, amine units, glycol dehydrators, fluid catalytic cracking unit and reformer generation, and flexi-coker coke burn

4.1.4 Vented emissions, including those emissions that are not combusted and are intentional or designed into the process or technology to occur during normal operations, and which may include: (1) venting from crude oil, condensate or natural gas product storage tanks, gas-driven pneumatic devices, gas samplers, chemical injection pumps, exploratory drilling, loading/ballasting/transit and loading racks, (2) venting resulting from maintenance/turn-arounds, which may include decoking of furnace tubes, well unloading, vessel and gas compressor depressurising, compressor starts, gas sampling, and pipeline blowdowns, and (3) venting from non-routine activities, which may include pressure relief valves, pressure control valves, fuel supply unloading valves and emergency shut-down devices

4.1.5 Fugitive emissions, which may include those emissions which can be individually found and ''fixed'' to make emissions 'near zero' and which may include emissions from valves, flanges, connectors, pumps, compressor seal leaks, catadyne heaters, and wastewater treatment and surface impoundments

5 The entity shall discuss whether its strategies, plans, or reduction targets are related to, or associated with, emissions limiting or emissions reporting-based programmes or regulations (for example, the EU Emissions Trading Scheme, Quebec Cap-and-Trade System, California Cap-and-Trade Program), including regional, national, international or sectoral programmes.

6 Disclosure of strategies, plans or reduction targets shall be limited to activities that were ongoing (active) or reached completion during the reporting period.

Water Management

Topic Summary

Depending on the extraction technique, exploration and production operations may consume significant quantities of water, which may expose entities to the risk of reduced water availability, regulations limiting use, or related cost increases, particularly in water-stressed regions. Contamination of local water resources can result from incidents involving produced water, flowback water, hydraulic fracturing fluids and other well

fluids. Historically, the possible impacts of hydraulic fracturing operations and the risk of groundwater supply contamination have raised concerns. Reducing water use and contamination through recycling, other water management strategies, and use of non-toxic fracturing fluids could create operational efficiency for entities and reduce their operating costs. Such strategies could also minimise the effects that regulations, water supply shortages and community-related disruptions have on operations.

Metrics

EM-EP-140a.1. (1) Total water withdrawn, (2) total water consumed; percentage of each in regions with High or Extremely High Baseline Water Stress

1 The entity shall disclose the amount of water, in thousands of cubic metres, withdrawn from all sources.

1.1 Water sources include surface water (including water from wetlands, rivers, lakes and oceans), groundwater, rainwater collected directly and stored by the entity, and water and wastewater obtained from municipal water supplies, water utilities or other entities.

2 The entity may disclose portions of its supply by source if, for example, significant portions of withdrawals are from non-freshwater sources.

2.1 Fresh water may be defined according to the local laws and regulations where the entity operates. If no legal definition exists, fresh water shall be considered to be water that has less than 1,000 parts per million of dissolved solids.

2.2 Water obtained from a water utility in compliance with jurisdictional drinking water regulations can be assumed to meet the definition of fresh water.

3 The entity shall disclose the amount of water, in thousands of cubic metres, consumed in its operations.

3.1 Water consumption is defined as:

3.1.1 Water that evaporates during withdrawal, use and discharge

3.1.2 Water that is directly or indirectly incorporated into the entity's product or service

3.1.3 Water that does not otherwise return to the same catchment area from which it was withdrawn, such as water returned to another catchment area or the sea.

4 The entity shall analyse all its operations for water risks and identify activities that withdraw and consume water in locations with High (40–80%) or Extremely High (>80%) Baseline Water Stress as classified by the World Resources Institute's (WRI) Water Risk Atlas tool, Aqueduct.

5 The entity shall disclose water withdrawn in locations with High or Extremely High Baseline Water Stress as a percentage of the total water withdrawn.

6 The entity shall disclose water consumed in locations with High or Extremely High Baseline Water Stress as a percentage of the total water consumed.

EM-EP-140a.2. Volume of produced water and flowback generated; percentage (1) discharged, (2) injected, (3) recycled; hydrocarbon content in discharged water

1 The entity shall disclose the volume, in thousands of cubic metres, of produced water and flowback fluid generated during its activities.

2 Produced water is defined as water (brine) obtained from the hydrocarbon bearing formation strata during the extraction of oil and gas. Produced water can include formation water, injection water, and any chemicals added downhole or during the oil/water separation process.

3 Flowback is defined as the recovered hydraulic fracturing fluid that returns to the surface during a hydraulic fracturing operation that may often be mixed with produced water.

4 The entity shall calculate the percentage of produced water and flowback fluid that was:

4.1 Discharged directly to the environment or indirectly discharged through a third party, such as a local wastewater treatment plant

4.2 Injected

4.3 Recycled for use in other wells, in fracturing fluids or in other drilling and production processes

5 The entity shall disclose the amount, in metric tons, of hydrocarbons water discharged to the environment.

5.1 The scope of disclosure includes produced water, flowback, process water, storm water or other water discharged to the environment.

5.2 Measurements of hydrocarbon content should be made using test methods required or approved by applicable legal or regulatory authorities (or equivalent applicable standards).

EM-EP-140a.3. Percentage of hydraulically fractured wells for which there is public disclosure of all fracturing fluid chemicals used

1 The entity shall disclose the percentage of hydraulically fractured wells for which there is public disclosure of all fracturing fluid chemicals used.

1.1 The percentage shall be calculated as the number of hydraulically fractured wells for which it provides public disclosure of all the chemical content of fracturing fluid, divided by the total number of hydraulically fractured wells.

1.2 The entity shall include in the percentage only those wells for which all fluid chemicals are publicly disclosed, including the chemicals that meet the definition of a trade secret.

2 Public disclosure may include posting to a publicly accessible corporate website.

EM-EP-140a.4. Percentage of hydraulic fracturing sites where ground or surface water quality deteriorated compared to a baseline

1 The entity shall calculate the percentage as: the total number of hydraulic fracturing well sites for which it detected a deterioration in the ground or surface water surrounding the well site as compared to a baseline measurement, divided by the total number of hydraulic fracturing well sites.

2 Deterioration in water quality is, at a minimum, defined as occurring when testing indicates:

2.1 Presence of thermogenic gas or a mixture of thermogenic and biogenic gas not present in baseline testing.

2.2 An increase in methane concentration by more than 5.0 mg/l between sampling periods.

2.3 Benzene, toluene, ethylbenzene, xylenes (BTEX compounds) or total petroleum hydrocarbons (TPH) are present in higher concentrations as compared to the baseline.

3 The entity shall determine whether water quality deteriorated against a baseline through monitoring of ground and surface water surrounding hydraulically fractured well sites.

3.1 Determinations shall be consistent with Chapter 3 of the Wyoming Oil and Gas Conservation Commission (WOGCC) Rules and Regulations, the Colorado Oil and Gas Conservation Commission's (COGCC) Rule 609 — Statewide Groundwater Baseline Sampling and Monitoring, or a jurisdictional equivalent.

3.2 The entity shall disclose the jurisdictional standard, guideline or regulation used for its calculation.

4 The initial baseline sample shall occur:

4.1 Prior to drilling or before installation of a surface oil and gas facility on a location

4.2 Prior to re-stimulation of a well, if more than 12 months have passed since the initial pre-drilling sampling event or the most recent re-stimulation sampling event

5 Ongoing monitoring shall occur with at least the following frequency:

5.1 One subsequent sampling between 12 and 18 months after well completion or facility installation

5.2 A second subsequent sampling between 60 and 78 months after the previous sampling event. Dry holes are exempt from this requirement

6 The entity shall collect initial baseline samples and subsequent monitoring samples from all available water sources within a one-half mile radius of a proposed well, multi-well site, or dedicated injection well.

6.1 The entity shall follow sampling guidance from the WOGCC and COGCC or jurisdictional equivalent for the collection of samples, including for instances when few or no sampling sites exist or are accessible.

7 If the entity does not conduct baseline water quality assessments and ongoing monitoring for any of its well sites, then it shall disclose the percentage of wells for which there is no baseline or ongoing monitoring.

8 The entity may disclose whether results of baseline groundwater quality tests and ongoing monitoring are communicated to applicable jurisdictional legal or regulatory authorities (where not required by local law) or residents and business owners in proximity to hydraulic fracturing sites.

Note to **EM-EP-140a.4**

1 The entity shall describe its policies and practices related to its management of ground and surface water quality.

2 Applicable policies and practices may include:

2.1 Well design and well integrity management

2.2 Hydraulic fracturing procedures

2.3 Surface facility design, including the use of backflow preventers, storage tank design and impoundment design

2.4 Surface and groundwater quality and testing

2.5 Chemicals management

2.6 Water reuse, processing and disposal

Reserves Valuation & Capital Expenditures

Topic Summary

Exploration and production (E&P) entities may be unable to extract a significant proportion of their proved and probable oil and gas reserves if greenhouse gas (GHG) emissions are controlled to limit global temperature increases. Entities with more carbon-intensive reserves and production and higher capital costs may face greater risks. Regulatory limits on GHG emissions, together with improved competitiveness of alternative energy technologies, could reduce global demand growth, and therefore reduce prices for oil and gas products. Extraction costs could increase with regulations that put a price on GHG emissions. These factors could affect the economic viability of oil and gas reserves. Regulatory actions that are more abrupt than anticipated, or those focusing on industries with high emissions, could impair asset values over a short period. Stewardship of capital resources and production decisions that consider near- and long-term trends related to climate change may mitigate potential asset impairment and maintain profitability and creditworthiness.

Metrics

EM-EP-420a.1. Sensitivity of hydrocarbon reserve levels to future price projection scenarios that account for a price on carbon emissions

1 The entity shall perform a sensitivity analysis of its reserves to determine how several future scenarios may affect the determination of whether the reserves are proved or probable.

2 The entity shall analyse the sensitivity of its current proven and probable reserves using the price trajectories published by the International Energy Agency (IEA) in its *World Energy Outlook* (WEO) publication, including:

2.1 Current Policies Scenario, which assumes no changes in policies from the mid-point of the year of publication of the WEO.

2.2 New Policies Scenario, which assumes that broad policy commitments and plans that have been announced by countries (including national pledges to reduce greenhouse gas emissions and plans to phase out fossil-energy subsidies), occur even if the measures to implement these commitments have yet to be identified or announced. This broadly serves as the IEA baseline scenario.

2.3 Sustainable Development Scenario, which assumes that an energy pathway occurs that is consistent with the goal of limiting the global increase in temperature to 1.5°C by limiting concentration of greenhouse gases in the atmosphere.

2.4 The entity shall consider the WEO scenarios as a normative reference; thus, any updates to the WEO made year-on-year shall be considered updates to this guidance.

3 The entity shall follow the applicable jurisdictional guidance for the following:

3.1 Classifying reserves as proved and probable

3.2 Conducting a reserves sensitivity analysis and disclosing, in the aggregate, an estimate of reserves for each product type based on various price and cost criteria, such as a range of prices and costs that may reasonably be achieved, including standardised futures prices or management's own forecasts

3.2.1 The entity shall disclose the price and cost schedules and assumptions on which disclosed values are based

3.3 Determining current (or base) case of reserve levels

4 The entity may use the following table format to summarise its findings:

Table 3. Sensitivity of reserves to prices by principal product type and price scenario

PRICE CASE	PROVED RESERVES			PROBABLE RESERVES		
(Scenario)	Oil (MMbbls)	Gas (MSm^3)	Product:A (measure)	Oil (MMbbls)	Gas (MSm^3)	Product:A (measure)

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PRICE CASE	PROVED RESERVES			PROBABLE RESERVES		
Current Policies Scenario (base)						
New Policies Scenario						
Sustainable Development Scenario						

5 The entity may disclose the sensitivity of its reserve levels in other price and demand scenarios in addition to those described above, particularly if these scenarios vary depending on the type of hydrocarbon reserves, regulatory environment in the countries or regions where exploration occurs, end-use of the entity's products, or other factors.

6 For additional sensitivity analyses, the entity should consider disclosing the following, per the Task Force on Climate- Related Financial Disclosures (TCFD) Recommendations Report Figure 8 as well as the Implementing the Recommendations of the TCFD Report, Section E:

6.1 The alternative scenarios used, including other 2°C or lower scenarios

6.2 Critical input parameters, assumptions and analytical choices for the climate-related scenarios used, particularly as they relate to key areas such as policy assumptions, energy deployment pathways, technology pathways and related timing assumptions

6.3 Time frames used for scenarios, including short-, medium- and long-term milestones (for example, how organisations consider timing of potential future implications under the scenarios used)

EM-EP-420a.2. Estimated carbon dioxide emissions embedded in proved hydrocarbon reserves

1 The entity shall calculate and disclose an estimate of the carbon dioxide emissions embedded in its proved hydrocarbon reserves.

1.1 Nota bene — this estimate applies a factor for potential CO_2 only and does not include an estimate for all potential greenhouse gas emissions, as these are dependent on downstream use (for example, utility electricity generation, industrial heating and electricity generation, residential heating and cooling, transportation, or use in petrochemicals, agrochemicals, asphalt and lubricants).

2 Estimated potential carbon dioxide emissions from proved hydrocarbon reserves shall be calculated according to the following formula, derived from Meinshausen et al.:

2.1 $E = R \times V \times C$, where:

2.1.1 E are the potential emissions in kilogrammes of carbon dioxide (kg CO_2);

2.1.2 R are the proved reserves in gigagrams (Gg);

2.1.3 V is the net calorific value in terajoules per gigagram (TJ/Gg); and

2.1.4 C is the effective carbon dioxide emission factor in kilogrammes CO_2 per terajoule (kg/TJ).

3 In the absence of data specific to the entity's hydrocarbon reserves, carbon content shall be calculated using default data for each major hydrocarbon resource published by the Intergovernmental Panel on Climate Change (IPCC) in its *2006 IPCC Guidelines for National Greenhouse Gas Inventories*.

3.1 The entity shall use default carbon content values per unit of energy listed in IPCC Table 1.3 Default Values of Carbon Content, Volume 2: Energy, Chapter 1.

3.2 The entity shall use calorific values per weight of hydrocarbon contained in IPCC Table 1.2 Default Net Calorific Values (NCVs) and Lower and Upper Limit of the 95% Confidence Intervals, Volume 2: Energy, Chapter 1.

4 The entity shall use engineering estimates to determine the weight of its hydrocarbon reserves in gigagrams.

5 For other assumptions required to estimate the carbon content of hydrocarbon reserves, the entity shall rely on guidance from the IPCC, the Greenhouse Gas Protocol or the International Energy Agency (IEA).

EM-EP-420a.3. Amount invested in renewable energy, revenue generated by renewable energy sales

1 The entity shall disclose the total amount spent, including capital and research and development expenditures, on renewable or alternative energy sources.

1.1 Such disclosure generally corresponds to the renewable energy technology areas per C-OG 9.6 of the CDP Climate Change Questionnaire.

2 The entity shall disclose the sales generated from renewable energy sources.

2.1 Such disclosure generally corresponds to the renewable energy strategic development areas Section C4.5a of the CDP Climate Change Questionnaire

3 Renewable energy is defined as energy from sources that are capable of being replenished quickly through ecological cycles, such as geothermal, wind, solar, hydro and biomass.

3.1 For the purposes of this disclosure, the scope of renewable energy from biomass sources is limited to materials certified to a third-party standard (for example, Forest Stewardship Council, Sustainable Forest Initiative, Programme for the Endorsement of Forest Certification or American Tree Farm System), materials considered 'eligible renewables' according to the Green-e Energy National Standard.

3.1.1 The entity shall consider the Green-e Energy National Standard as a normative reference; thus, any updates to the Standard made year-on-year shall be considered updates to this guidance.

4 The entity shall consider the CDP Climate Change Questionnaire a normative reference; thus, any updates made year-on-year shall be considered updates to the guidance.

EM-EP-420a.4. Discussion of how price and demand for hydrocarbons or climate regulation influence the capital expenditure strategy for exploration, acquisition and development of assets

1 The entity shall discuss how projections for price and demand for hydrocarbon products and the path of climate regulation influence the entity's capital expenditure (CAPEX) investment strategy.

1.1 This discussion should include the entity's projections and assumptions about future hydrocarbon prices and the likelihood that various price and demand scenarios occur.

2 The entity shall discuss the implications of how price and demand scenario planning (EM-EP-420a.1) may affect decisions to explore, acquire and develop new reserves.

3 The entity may discuss factors that materially influence its CAPEX decision making, which may include:

3.1 How the scope of climate change regulation—such as which countries, regions or industries are likely to be affected—may influence the type of hydrocarbon on which the entity focuses its exploration and development

3.2 Its view of the alignment between the time horizon over which price and demand for hydrocarbons may be affected by climate regulation and time horizons for returns on capital expenditures on reserves

3.3 How the structure of climate regulation—a carbon tax versus cap-and-trade—may differently affect price and demand, and thus the entity's capital expenditure decision making

4 The entity may discuss how these trends affect decision-making in the context of various types of reserve expenditures, including development of assets, acquisition of properties with proved reserves, acquisition of properties with unproved reserves, and exploration activities.

4.1 The entity shall discuss capital expenditures, regardless of the accounting method it uses (full cost or successful efforts).

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