Exposure Draft

Guidance Note on Accounting for Oil and Gas Producing Activities (Ind AS)

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Exposure Draft

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Research Committee of the Institute of Chartered Accountants of India invites comments on any aspect of this Exposure Draft of the 'Guidance Note on Accounting for Oil and Gas Producing Activities (Ind AS)'. Comments are most helpful if they indicate the specific paragraph or group of paragraphs to which they relate, contain a clear rationale and, where applicable, provide a suggestion for alternative wording.

Comments should be submitted in writing to the Secretary, Research Committee, The Institute of Chartered Accountants of India, ICAI Bhawan, Post Box No. 7100, Indraprastha Marg, New Delhi – 110 002, so as to be received not later than ***August 31, 2016.*** *Comments can also be sent by e-mail at* research@icai.in .

This Guidance Note is to be applied by the specified companies to whom Ind ASs are applicable as per rule 4 of the Companies (Indian Accounting Standard) Rules, 2015 ('referred to as Ind AS companies') from the date from which Ind ASs are applicable to such companies.

Introduction

1. Oil and gas producing industry, which is extractive in nature, involves activities relating to acquisition of mineral interests in properties, exploration (including prospecting), development and production of oil and gas. Oil and gas also include coal bed methane (CBM) and shale gas. These activities may be carried out onshore or offshore. The aforesaid activities are collectively referred to as upstream operations and form the 'Upstream Petroleum Industry'. The industry is commonly referred to as the 'E&P' industry. The peculiar nature of the industry requires establishment of industry-specific accounting principles in relation to expense recognition, measurement and disclosure.

Objective

2. Considering the peculiar nature of E&P industry, Indian Accounting Standard (Ind AS) 16, *Property, Plant and Equipment* and Indian Accounting Standard (Ind AS) 38 , *Intangible Assets* , do not apply to recognition and measurement of exploration and evaluation assets [para 3(c) of Ind AS 16 and para 2 (c) of Ind AS 38 respectively]. Indian Accounting Standard (Ind AS) 106, *Exploration and Evaluation of Mineral Resources*, applies to such assets.

3. The objective of this Guidance Note is to provide guidance on the accounting principles contained in Indian Accounting Standards (Ind AS) to accounting for costs incurred on activities relating to acquisition of interests in properties, exploration, development and production of oil

and gas.

Scope

4. This Guidance Note applies to costs incurred on acquisition of mineral interests in properties, exploration, development and production of oil and gas activities, i.e., upstream operations. This Guidance Note also deals with other accounting aspects such as accounting for abandonment costs and impairment of assets that are peculiar to the entities carrying on oil and gas producing activities. It does not address accounting and reporting issues relating to the transporting, refining and marketing of oil and gas. This Guidance Note also does not apply to accounting for:

(a) activities relating to the production of natural resources other than oil and gas; and
(b) the production of geothermal resources or the extraction of hydrocarbons as a by-product of the production of geothermal and associated resources.

Definitions

5. For the purpose of this Guidance Note, the following terms are used with the meanings specified:

(i) *Appraisal Well:* A well drilled as part of an appraisal drilling programme, which is carried out to determine the physical extent of oil and gas reserves and likely production rate of a field.

(ii) *Depreciation:* Depreciation is the systematic allocation of the depreciable amount of an asset over its useful life. Depreciation includes amortisation of assets whose useful life is predetermined. Depreciation also includes 'depletion' of natural resources through the process of extraction or use.

(iii) *Development Well:* A well drilled, deepened, completed or re-completed within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(iv) *Exploratory Well:* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well, as those items are defined separately.

(v) *Exploration and evaluation assets*: Exploration and evaluation expenditures recognised as assets in accordance with the entity's accounting policy.

(vi) *Exploration and evaluation expenditures*: Expenditures incurred by an entity in connection with the exploration for and evaluation of mineral resources before the technical feasibility and

commercial viability of extracting a mineral resource are demonstrable.

(vii) *Exploration for and evaluation of mineral resources*: The search for mineral resources, including minerals, oil, natural gas and similar non-regenerative resources after the entity has obtained legal rights to explore in a specific area, as well as the determination of the technical feasibility and commercial viability of extracting the mineral resource.

(viii) *Field:* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms 'structural feature' and 'stratigraphic condition' are intended to identify localised geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(ix) (a) *Oil and Gas Reserves* Oil and gas reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permissions and financing required to implement the project.

(b) All oil and gas reserve estimates involve some degree of uncertainty. Uncertainty depends chiefly on availability of reliable geological and engineering data at the time of the estimate and interpretation of data.

(c) The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

(x) *Based on relative degree of uncertainty, oil and gas reserves can be classified as 'Proved Oil and Gas Reserves' and 'Unproved Oil and Gas Reserves'.*

(xi) *Proved Oil and Gas Reserves:* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate. The project to extract the

hydrocarbons must have commenced or the entity must be reasonably certain that it will commence the project within a reasonable time.

Proved oil and gas reserves can be classified as 'Proved developed oil and gas reserves' and 'Proved undeveloped oil and gas reserves'.

(xii) *Proved Developed Oil and Gas Reserves:* Proved developed oil and gas reserves are reserves that can be expected to be recovered:

(a) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

(xiii) (a) *Proved Undeveloped Oil and Gas Reserves: (a)* Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(b) Reserves on undrilled acreage should be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(c) Undrilled locations can be classified as having proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within a reasonable time, unless the specific circumstances, justify a longer time.

(d) Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

(xiv) *Probable Reserves:* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserve estimates.

(xv) *Reservoir:* A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(xvi) *Service Well:* A service well is a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for gas injection (natural

gas, propane, butane, or flue gas), water injection, steam injection, air injection, polymer injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

(xvii) *Stratigraphic Test Well:* A stratigraphic test is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells (sometimes called expendable wells) are classified as follows:

(a) *Exploratory-type stratigraphic test well:* A stratigraphic test well drilled, but not in a proved area. These wells are more like exploratory wells than like geological and geophysical (G&G) activities, even though these wells cannot be used to produce the reserves.

(b) *Development-type stratigraphic test well:* A stratigraphic test well drilled in a proved area.

(xviii) *Unit of Production (UOP) method:* The method of depreciation (depletion) under which depreciation (depletion) is calculated on the basis of the number of production or similar units expected to be obtained from the asset by the entity.

6. The glossary of certain other terms commonly used in E&P industry and relevant for the Guidance Note is given in Appendix 1.

Classification of Activities and Related Costs

Acquisition Activities

7. Activities carried out by an E&P entity towards the acquisition of right(s) to explore, develop and produce oil and gas, constitute acquisition activities. Once the areas of oil and gas finds are identified, the E&P entity approaches the owner who owns the rights for the exploration, development and production of the underground minerals in respect of the property or area. In order to undertake surveys and exploration activities, an E&P entity has to first obtain a Petroleum Exploration License (PEL) or Letter of Authority (LOA) in India or similar permit elsewhere, by whatever name called. For engaging in development and production activities, an entity has to obtain a Mining Lease (ML) in India. Similarly, other countries may require specific permissions/lease/license for the purpose. The rights for exploration, development or production may also be acquired by entering into a farm-in arrangement (transfer of part of oil & gas interest between parties).

Acquisition Costs

8. Acquisition costs cover all costs incurred to purchase, lease or otherwise acquire a property or mineral right proved or unproved. These include lease/signature bonus, brokers' fees, legal costs, cost of temporary occupation of the land including crop compensation paid to farmers, consideration for farm-in arrangements and all other costs incurred in acquiring these rights. These are costs incurred in acquiring the right to explore, drill and produce oil and gas including the initial costs incurred for obtaining the PEL/LOA and ML. Annual licence fees are excluded. In case the acquisition cost pertains to more than one field, it should be apportioned to the related field on a fair and reasonable basis.

9. Expenditure incurred before an entity has obtained the right(s) to explore, develop and produce oil and gas, i.e., the pre-acquisition costs, e.g., data collection and analysis costs incurred for the purpose of identifying the oil and gas asset to be acquired, are not included in acquisition costs. Such costs are accounted for in accordance with the general principles laid down in the framework for preparation and presentation of financial statements and other applicable accounting pronouncements.

Activities relating to exploration for and evaluation of mineral resources

10. Exploration and evaluation activities cover the prospecting activities conducted in the search for oil and gas after an entity has obtained legal right to explore a specific area, as well as activities towards determination of the technical feasibility and commercial viability of extracting the oil and gas. In the course of an appraisal programme these activities include but are not limited to aerial, geological, geophysical, geochemical, palaeontological, palynological, topographical and seismic surveys, analysis, studies and their interpretation, investigations relating to the subsurface geology including structural test drilling, exploratory type stratigraphic test drilling, drilling of exploration and appraisal wells and other related activities such as surveying, drill site preparation and all work necessarily connected therewith for the purpose of oil and gas exploration.

Exploration and evaluation costs

11. Principal types of exploration and evaluation costs cover all directly attributable expenditure. General and administrative costs are included in the exploration and evaluation cost only to the extent that those costs can be specifically attributable to the related exploration and evaluation assets. In all other cases, these costs are expensed as incurred. For example, general and administrative costs such as directors' fees, secretarial and share registry expenses, salaries and other expenses of general management, etc., are usually recognised as expenses when incurred. Exploration and evaluation costs include depreciation and applicable operating costs of related support equipment and facilities and other costs of exploration and evaluation activities that are:

(i) costs of surveys and studies mentioned in paragraph 10 above, rights of access to

properties to conduct those studies (e.g., costs incurred for environment clearance, defence clearance, etc.), and salaries and other expenses of geologists, geophysical crews and other personnel conducting those studies. Collectively, these are referred to as geological and geophysical or 'G&G' costs;

(ii) costs of carrying and retaining undeveloped properties, such as delay rental, ad valorem taxes on properties, legal costs for title defence, maintenance of land and lease records and annual licence fees in respect of Petroleum Exploration License;

(iii) dry hole contributions and bottom hole contributions;

(iv) costs of drilling and equipping exploratory and appraisal wells and related analysis; and

(v) costs of drilling exploratory-type stratigraphic test wells.

Development Activities

12. Development activities cover the activities conducted after determination of the technical feasibility and commercial viability of extracting oil and gas. These activities include, but are not limited to the purchase, shipment or storage of equipment and materials used in developing oil and gas accumulations, completion of successful exploration wells, drilling; completion; re-completion; and testing of development/service wells, laying of gathering lines, construction of offshore platforms and installations, installation of separators, tankages, pumps, artificial lift and other producing and injection facilities required to produce, process and transport oil or gas into main oil storage or gas processing facilities, either onshore or offshore, including laying of infield pipelines, installation of the said storage or gas processing facilities.

Development Costs

13. Development costs cover all the directly attributable expenditure incurred in respect of the development activities including costs incurred to:

(i) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines to the extent necessary in developing the proved oil and gas reserves;

(ii) drill and equip development wells (whether successful or unsuccessful), development-type stratigraphic test wells and service wells including the cost of platforms and of well materials and equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(iii) acquire, construct and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants and utility and waste disposal systems; and

(iv) provide advanced recovery system.

14. Development costs also include depreciation and applicable operating cost of related support equipment and facilities in connection with development activities and annual license fees in respect of Mining Lease.

15. General and administrative costs are included in the development cost only to the extent that those costs can be specifically attributable to the related field. In all other cases, these costs are expensed as incurred. For example, general and administrative costs such as directors' fees, secretarial and share registry expenses, salaries and other expenses of general management, etc., are usually recognised as expenses when incurred.

Production Activities

16. Production activities consist of pre-wellhead (e.g., lifting the oil and gas to the surface, operation and maintenance of wells and extraction rights, etc.,) and post-wellhead (e.g., gathering, treating, field transportation, field processing, etc., upto the outlet valve on the lease or field production storage tank, etc.) activities for producing oil and/or gas.

Production Costs

17. Production costs consist of direct and indirect costs incurred to operate and maintain an entity's wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities. Examples of production costs are :

(a) Pre-wellhead costs :

Costs of labour, repairs and maintenance, materials, supplies, fuel and power, property taxes, insurance, severance taxes, royalty, etc., in respect of lifting the oil and gas to the surface, operation and maintenance including servicing and work-over of wells.

(b) Post-wellhead costs :

Costs of labour, repairs and maintenance, materials, supplies, fuel and power, property taxes, insurance, etc., in respect of gathering, treating, field transportation, field processing, including cess up to the outlet valve on the lease or field production storage tank, etc.

Accounting for "Acquisition", "Exploration And Evaluation" and " Development Costs"

18. An entity should capitalise acquisition costs as an intangible asset or tangible asset, based on its nature. For example, acquisition cost incurred to obtain right to explore should be capitalized as intangible asset.

19. The exploration and evaluation expenditure should be accounted for in accordance with the requirements of Ind AS 106. Accordingly, an entity should determine an accounting policy, specifying which expenditures are recognised as exploration and evaluation assets and apply the

policy consistently. In making this determination, an entity considers the degree to which the expenditure can be associated with finding specific mineral resources.

20. An entity should classify exploration and evaluation assets as tangible or intangible according to the nature of the assets acquired and apply the classification consistently. Some exploration and evaluation assets are treated as intangible, whereas others are tangible. To the extent that a tangible asset is consumed in developing an intangible asset, the amount reflecting that consumption is part of the cost of the intangible asset. However, using a tangible asset to develop an intangible asset does not change a tangible asset into an intangible asset.

21 Once the technical feasibility and commercial viability of extracting oil and gas are determinable, the exploration and evaluation assets should be reclassified as capital work-in-progress or intangible asset under development, as the case may be. Exploration and evaluation assets should be assessed for impairment, and impairment loss if any, should be recognised, before such reclassification. Subsequent development costs should be capitalised when incurred.

22. All costs other than those covered in paragraph 8 and paragraphs 10 to paragraph 15 should be charged as expense when incurred (Also refer to paragraph9 in relation to the accounting treatment for pre-acquisition cost).

23. When a well is ready to commence commercial production, the capitalised costs referred to in above paragraphs corresponding to proved developed oil and gas reserves should be reclassified as 'completed wells/producing wells' from "capital work-in-progress/intangible asset under development" to the gross block of assets. With respect to acquisition costs, the entire cost should be capitalised from "capital work-in-progress/intangible asset under development" to the gross block of assets. Normally, a well is ready to commence commercial production on establishment of proved developed oil and gas reserves.

24. The exploration and evaluation expenditure which does not result in discovery of proved oil and gas reserves should be charged as expense or capitalised depending upon the accounting policy adopted by an entity, as mentioned in paragraph 19 above.

25. Expenditure incurred on exploratory wells which were written off in the past and started producing subsequently, cannot be reinstated.

Depreciation (Depletion)

26. Depreciation (Depletion) is calculated, using the unit of production method. The application of this method results in oil and gas assets being written off at the same rate as the quantitative depletion of the related reserve. For the properties or groups of properties containing both oil reserves and gas reserves, the units of oil and gas used to compute depletion are converted to a common unit of measure on the basis of their approximate relative energy content, without considering their relative sales values (general approximation is 1000 cubic meters of gas is equivalent to 1 metric tonne of oil). Unit-of-production depletion rates are revised whenever there is an indication of the need for revision but at least

once a year. These revisions are accounted for prospectively as changes in accounting estimates, i.e., a change in the estimate affects the current and future periods, but no adjustment is made in the accumulated depletion applicable to prior periods.

27. The depreciation charge or the UOP charge for the acquisition cost within a field is calculated as under:

UOP charge for the period = UOP rate x Production for the period

UOP rate = Acquisition cost of the field /Proved Oil and Gas Reserves

28. The depreciation charge or the Unit of Production (UOP) charge for all capitalised costs excluding acquisition cost within a field is calculated as under:

UOP charge for the period = UOP rate x Production for the period

UOP rate = Depreciation base of the field /Proved Developed Oil and Gas Reserves

29. Depreciation base of the field should include:

(a) Gross block of the field (excluding acquisition costs)

(b) Estimated dismantlement and abandonment costs net of estimated salvage values pertaining to proved developed oil and gas reserves and should be reduced by the accumulated depreciation and any accumulated impairment charge of the field.

30. 'Proved Oil and Gas Reserves' for the purpose of paragraph 27 comprise proved oil and gas reserves estimated at the end of the period as increased by the production during the period. 'Proved Developed Oil and Gas Reserves' for the purpose of paragraph 28 comprise proved developed oil and gas reserves estimated at the end of the period as increased by the production during the period.

31. The depreciation method used should reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. The entity selects the method that most closely reflects the expected pattern of consumption of the future economic benefits embodied in the asset. Accordingly, oil and gas assets for the purpose of applying UOP method should not include assets having a different pattern of consumption which is not related to depletion of oil and gas reserves . The depreciation method applied should be reviewed at least at each financial year-end and if there has been a significant change in the expected pattern of consumption of the future economic benefits embodied in the asset, the method should be changed to reflect the changed pattern.

Accounting for Production Costs

32. Production costs, mentioned in paragraph 17 above, become part of the cost of oil and gas produced, along with depreciation (depletion) of capitalised acquisition, exploration and

development costs.

Accounting for Cost of Support Equipment and Facilities

33. The cost of acquiring or constructing support equipment and facilities used in E&P activities should be capitalised in accordance with Ind AS 16 . Depreciation on such equipment and facilities should be arrived at in accordance with Ind AS 16, and accounted for as exploration and evaluation cost, development cost or production cost, as may be appropriate.

Accounting for Abandonment Costs

34. Abandonment costs are the costs incurred on discontinuation of all operations and surrendering the property back to the owner. These costs relate to plugging and abandoning of wells, dismantling of wellheads; production; and transport facilities and to restoration of producing areas in accordance with license requirements and the relevant legislation.

35. The eventual liability for abandonment cost should be recognised when the obligation arises on the ground that a liability to remove an installation exists the moment it is installed. Thus, an entity should capitalise as part of property, plant and equipment or intangible asset, as the case may be, the amount of provision required to be created for subsequent abandonment. The provision for estimated abandonment costs should be made at current prices considering the environment and social obligations, terms of mining lease agreement, industry practice, etc. Where the effect of the time value of money is material, the amount of the provision should be the present value of the expenditures expected to be required to settle the obligation. The discount rate (or rates) should be a pre-tax rate (or rates) that reflect current market assessments of the time value of money and the risks specific to the liability. The discount rate should not reflect risks for which future cash flow estimates have been adjusted. Changes in the measurement of existing abandonment costs that result from changes in the estimated timing or amount of the outflow of resources embodying economic benefits required to settle the obligation or a change in the discount rate should be added to, or deducted from the related field in the current period and would be considered for necessary depletion (depreciation) prospectively. However, the change in the estimated provision due to the periodic unwinding of the discount should be recognized in profit or loss as it occurs. Since abandonment costs do not reflect borrowed funds, the unwinding cost would not be a borrowing cost eligible for capitalisation

Abandonment of Properties

36. No gain or loss should be recognised if only an individual well or individual item of equipment is abandoned or decided as dry as long as the remainder of the wells in the field continues to produce oil or gas. When the last well on the field ceases to produce and the entire field is abandoned, gain or loss should be recognised.

Capitalisation of Borrowing Costs

37. Capitalisation of borrowing costs should be in accordance with the Indian Accounting Standard (Ind AS) 23,, '*Borrowing Costs*'.

Impairment of Assets

Exploration and evaluation assets

38. An entity should determine an accounting policy for allocating exploration and evaluation assets to cash-generating units or groups of cash-generating units for the purpose of assessing such assets for impairment. Each cash-generating unit or group of units to which an exploration and evaluation asset is allocated should not be larger than an operating segment determined in accordance with Indian Accounting Standard (Ind AS) 108, *Operating Segments*.

39. Exploration and evaluation assets should be assessed for impairment when facts and circumstances suggest that the carrying amount of an exploration and evaluation asset may exceed its recoverable amount.

40. One or more of the following facts and circumstances indicate that an E&E entity should test for impairment during the exploration phase (the list is not exhaustive):

(a) the period for which the entity has the right to explore in the specific area has expired during the period or will expire in the near future, and is not expected to be renewed.

(b) substantive expenditure on further exploration activities in the specific area is neither budgeted nor planned.

(c) exploration in the specific area have not led to the discovery of commercially viable quantities of reserves and the entity has decided to discontinue such activities in the specific area.

(d) sufficient data exist to indicate that, although a development in the specific area is likely to proceed, the carrying amount of the exploration cost is unlikely to be recovered in full from successful development or by sale.

41. In any such case, or similar cases, the entity should perform an impairment test in accordance with Indian Accounting Standard (Ind AS) 36, *Impairment of Assets*. Any impairment loss is recognised as an expense in accordance with Ind AS 36.

Development and production assets

42. In case of development/producing fields, the proved reserves would have been established. Accordingly, in case any of the indicators as per the general principles of Ind AS 36 or if any specific indicators exist, its recoverable amount should be determined for the purposes of impairment analysis.

43. For the purposes of estimating future cash flows for determining value in use as per the requirements of Ind AS 36, E&P entities should consider up to proved and probable reserves. For this purpose, full estimate of expected cost of evaluation/development (i.e., in arriving at the proved reserves) should be considered while applying the impairment test. In accordance with the requirements of Ind AS 36, in measuring value in use, an entity should base

cash flow projections on reasonable and supportable assumptions that represent management's best estimate of the range of economic conditions that will exist over the remaining useful life of the asset. Accordingly, management's estimates of future cash flows usually takes a long-term view of the range of economic conditions over the remaining useful life of the asset and, are not based on the relatively short-term changes in the economic conditions.

44. In certain circumstances, for example, where two or more fields use common production and transportation facilities, those fields may be sufficiently economically interdependent to constitute a single cash generating unit for the purposes of Ind AS 36, in which case impairment test should be performed in aggregate for those fields.

Accounting for Interests in Joint Ventures

45. Many E&P entities enter into joint venture agreements for oil and gas exploration, development and production. In case of such arrangements, the accounting principles prescribed in Indian Accounting Standard (Ind AS) 111, *Joint Arrangements*, should be applied. In accordance with the requirements of Ind AS 111, an entity should determine the type of joint arrangement in which it is involved. The classification of a joint arrangement as a joint operation or a joint venture depends upon the rights and obligations of the parties to the arrangement. A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Those parties are called joint operators. A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. Those parties are called joint venturers. An entity applies judgement when assessing whether a joint arrangement is a joint operation or a joint venture. An entity should determine the type of joint arrangement in which it is involved by considering its rights and obligations arising from the arrangement. An entity assesses its rights and obligations by considering the structure and legal form of the arrangement, the terms agreed by the parties in the contractual arrangement and, when relevant, other facts and circumstances. Subject to evaluation of specific facts and circumstances, generally, in the Indian context, unincorporated joint ventures constituted under the production sharing contracts are likely to be in the form of joint operations.

Disposal of Interest

46. In case an entity entity, sells a part of its interest in a field, gain or loss should be recognised in the statement of profit and loss, except that no gain should be recognised at the time of such sale if substantial uncertainty exists about the recovery of the costs applicable to the retained interest or the entity has substantial obligation for future performance. The gain in such a situation (for example, in the exploratory phase) should be treated as recovery of cost related to that field.

Accounting for Side-Tracking Expenditure

47. Sometimes an E&P activity requires a second (or higher) attempt to drill a wellbore after the first wellbore has been junked (generally referred to 'side-track'). This saves re-drilling the top

part of the hole but requires drop back to a smaller wellbore size in the sidetrack. In case of an exploratory well, the cost of side-tracking should be treated in the same manner as the cost incurred on a new exploratory well. The cost of abandoned portion should be treated in the same manner as the cost of dry well, in line with the policy of accounting followed.

48. In case of development wells, the entire costs of abandoned portion and side-tracking should be capitalised.

49. In case of producing wells, if the side-tacking results in additional proved developed oil and gas reserves or increases the future benefits therefrom beyond previously assessed standard of performance, e.g., allows accelerated production (other than from normal work-over), the cost incurred on side-tracking should be capitalised, whereas the cost of abandoned portion of the well due to side-tracking should be depleted in the normal way. Otherwise, the cost of side-tracking should be charged as expense and the cost of abandoned portion should be depleted in the normal way.

Accounting for Carried Interest

50. There are several types of "carried interest" arrangements that arise in practice. Each arrangement may be unique and would require careful analysis in order to determine the substance of the arrangement. For example, a part of a participating interest in an unproved property may be assigned to effect a "carried interest" arrangement whereby the assignee (the carrying party) agrees to defray all costs of drilling, developing, and operating the property and is entitled to all of the revenue from production from the property, excluding any third party interest, until all of the assignee's costs have been recovered, after which the assignor will share in both costs and production, based on the agreed arrangement. In such an arrangement, the carried party should make no accounting for any costs and revenue until recoupment (payout) of the carried costs by the carrying party. Subsequent to payout, the carried party should account for its share of revenue, operating expenses, and subsequent development costs, if the agreement provides for subsequent sharing of costs rather than a carried interest. During the payout period, the carrying party should record all costs, including those carried, as per its normal accounting policy, and should record all revenue from the property including that applicable to the recovery of costs carried.

Changes in Accounting Policies

51. An entity may change its accounting policies for exploration and evaluation expenditures if the change makes the financial statements more relevant to the economic decision-making needs of users and no less reliable, or more reliable and no less relevant to those needs. An entity should judge relevance and reliability using the criteria in Ind AS 8.

52. To justify changing its accounting policies for exploration and evaluation expenditures, an entity should demonstrate that the change brings its financial statements closer to meeting the criteria in Ind AS 8, but the change need not achieve full compliance with those criteria.

Determination of functional currency

53. Entities in E&P industry frequently undertake transactions in different currencies. An entity should determine its functional currency in accordance with the principles laid down in Indian Accounting Standard (Ind AS) 21, *The Effects of Changes in Foreign Exchange Rates*. As per Ind AS 21, functional currency is the currency of the primary economic environment in which an entity operates, which is normally the one in which it primarily generates and expends cash. An entity considers the factors specified in Ind AS 21 for determining its functional currency. In many cases, due to the nature of E&P industry, transactions are denominated in a currency which may be different from the currency of the primary economic environment of transacting parties. In such cases, merely the fact that the transactions are denominated in such a currency may not necessarily be the factor to determine the functional currency since such a currency may be used due to its being a widely traded currency and may not be reflective of a currency of the primary economic environment in which transacting parties operate. In such cases, determination of functional currency involves judgement based on consideration of all the factors specified in Ind AS 21 in the context of specific facts and circumstances

Presentation

54. The carrying amounts of tangible and intangible oil and gas assets should be classified separately as tangible and intangible non-current assets, capital work-in-progress and intangible assets under development, as the case may be.

55. For the purpose of paragraph 54 above, oil and gas assets should be classified as tangible and intangible, based on the nature of the asset. Determining whether the nature of oil and gas assets is tangible or intangible should reflect whether the cost is incurred towards creation of a physical (tangible) asset that will itself be used or intangible knowledge. For example, a producing well which is used to extract reserves is classified as a tangible non-current asset. However, an exploratory well may only provide knowledge, and accordingly, is classified as intangible asset under development.

56. Examples of oil and gas assets that might be classified as intangible include:

- acquired rights to explore
- costs of surveys and studies, where capitalised
- exploratory drilling costs.

Examples of oil and gas assets that might be classified as tangible assets include:

- development drilling costs
- piping and pumps
- producing wells

to the extent that a tangible asset is consumed in developing an intangible asset, the amount of consumption of that asset is treated as part of the cost of the intangible asset created. However, the asset being used remains a tangible asset till such consumption.

Disclosure

57. Besides the disclosures required by applicable Ind ASs and statutes, an E&P entity should disclose the following in its financial statements:

(i) The accounting policies followed.

(ii) Net quantities of an entity's interests in proved reserves and proved developed reserves of (a) oil (including condensate and natural gas liquids) and (b) gas , as at the beginning and additions, deductions, production and closing balance.

(iii) Net quantities of an entity's interest in proved reserves and proved developed reserves of (a) oil and (b) gas should also be disclosed on the geographical basis.

(iv) The reporting of reserve quantities should be stated in metric tonnes for oil reserves and cubic meters for gas reserves.

(v) Description and net quantities of an entity's interest in reserves used as a basis for impairment assessment, if applicable.

(vi) Basis of determination of cash generating unit used for impairment assessment purposes.

(vii) Frequency of reserve evaluation, principal assumptions used and involvement of any external expert(s), if used.

(viii) Exploration cost written-off during the period

(ix) Explanation of changes in reserve estimates.

Appendix 1

Glossary

1. Abandon

To discontinue attempts to produce oil and gas from a mining lease area or a well and to plug the reservoir in accordance with regulatory requirements and salvage all recoverable equipments

2. Block

A defined area for purposes of licensing or leasing to an entity or entities for exploration, development and production rights.

3. Bottom-Hole Contributions

Money or property paid to an operator for use in drilling a well on property in which the payer has no property interest. The contributions are payable when the well reaches a pre-determined depth, regardless of whether the well is productive or non-productive. The payer may receive proprietary information on the well's potential productivity.

4. Condensate

Low vapour pressure hydrocarbons obtained from Natural Gas through condensation or extraction and refer solely to those hydrocarbons that are liquid at normal surface temperature and pressure conditions.

5. Dry Hole

A well, which has proved to be non-productive.

6. Dry Hole Contribution

A contribution made by one entity to costs incurred by another entity that is drilling a nearby well to obtain information from the entity drilling the well; the contribution is made when the well is complete and is found to be unsuccessful.

7. Geological and Geophysical Studies (G&G)

Processes which seek surface or subterranean indications of earth structure or formation where experience has shown the possibility of existence of mineral deposits.

8. Geological Survey

An exploratory programme directed to examination of rock and sediments obtained by boring or drilling, or by inspection of surface outcroppings.

9. Geophysical Survey

A study of the configuration of the earth's crust in a given area, as determined by the use of seismic, gravity, magnetic and geo-chemical procedures.

10. Mining Lease

The license issued for offshore and onshore properties for conducting development and production activity.

11. Natural Gas Liquids (NGL)

Hydrocarbons (primarily ethane, propane, butane and natural gasoline) which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature.

12. Petroleum Exploration License

The license issued for offshore and onshore properties for conducting exploration activity.

13. Support Equipment and Facilities

Equipment and facilities of the nature of service units, camp facilities, godowns (for stores and spares), workshops (for equipment repairs), transport services (trucks and helicopters), catering facilities and drilling and seismic equipment.

14. Work-Over

Remedial work to the equipment within a well, the well pipework or relating to attempts to increase the rate of flow.