ACCOUNTING FOR WELL WORKOVERS UNDER IFRS

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The term "workover" is used to refer to a broad range of well intervention activities which are performed on, within or through the wellbore of an oil or gas well after the well is initially completed. Workovers rank among the most complex, difficult and expensive types of wellwork as they not only require heavy equipment and a crew, but also require that the well be shut down and production stopped during workover activities.

I. Reasons for Workovers

As any work performed on the wellbore which changes the flowing characteristics of the well or which corrects a problem within the wellbore can be classified as a workover, there are a myriad of reasons why workovers are performed. Some common reasons for workovers include:

- Improve unsatisfactory production or injection rates;
- Repair or replace downhole equipment or tubulars;
- Supplemental recovery project requirements;
- Regulatory requirements to reduce gas/oil ratios, isolate zones or install safety equipment;
- Reservoir data gathering such as production/injection testing; and
- Abandonments.

The majority of workovers are performed due to an abnormal decline in a well's productivity. This decline can be the result of reservoir inflow or wellbore outflow problems. Inflow problems are caused by the flow characteristics of the particular reservoir and can often be corrected by well stimulation procedures such as acidizing, fracturing, scale and paraffin treatments or by reperforating the wellbore. Outflow problems, on the other hand, may require equipment changes, cleanouts and chemical treatments.

A very large number of workovers are due to mechanical issues such as the failure of cement, tubulars, packers, wireline components, valves or artificial lift equipment such as bottomhole pumps. These failures are particularly common with what are known in the industry as "sour wells" (i.e., those containing hydrogen sulphide (H_2S)) due to their corrosive operating environment or those prone to contaminant infiltration, such as sand, into the wellbore. In most cases, the failed mechanical equipment must be pulled and replaced using a specialized rig.

It is not uncommon for a project to change from a routine maintenance activity to major equipment replacement due to downhole conditions found during the initial workover activity. Due to the cost of mobilizing and setting up service rigs, there is an economic incentive to perform the unplanned equipment replacement during the same workover if possible.

II. Bottomhole Pumps and Other Downhole Equipment

A large percentage of workovers relate to the replacement or rebuilding of downhole equipment and, in particular, bottomhole pumps. As illustrated in the simplified diagram that appears on the following page, the major equipment in a wellbore falls into six broad categories:

- **Bottomhole pumps**, which increase pressure on the producing formations in order to lift oil and gas more easily to the surface. These include positive cavity pumps ("PCPs") and electric submersible pumps ("ESPs").[1]

- **Casing**, which is typically comprised of heavy-walled steel pipe run inside the wellbore and cemented into place. It provides wellbore stability and isolates the producing formation from other zones.

- **Tubing**, which is run inside the casing. It is the conduit through which oil and gas are brought from the producing formations to the surface.

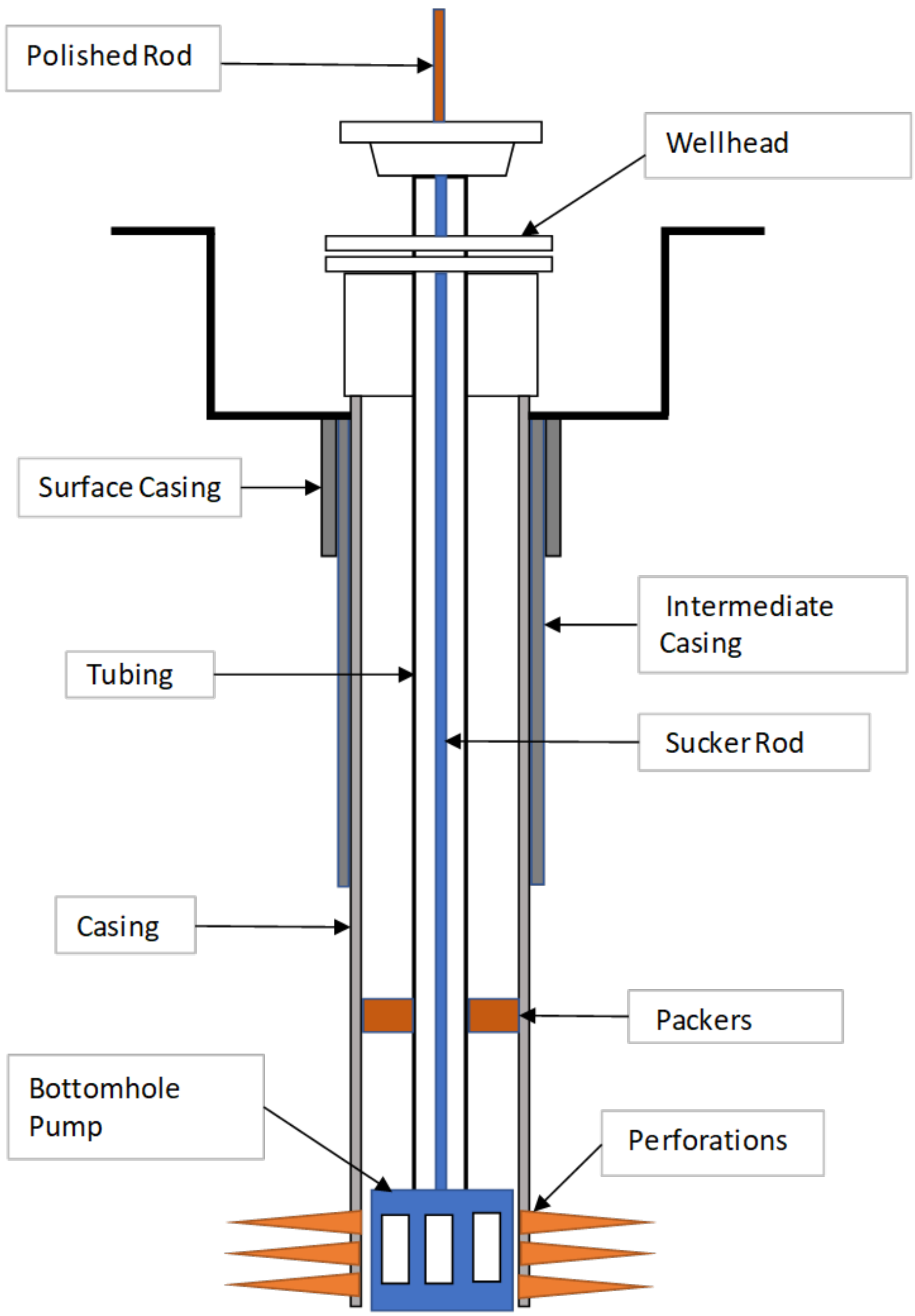
- **Sucker rods**, which are long jointed rods typically made of steel or fibreglass. These rods are run inside the tubing and connect bottomhole pump components to the surface. At the surface, the rods are attached to a pumpjack which provides the stroking action necessary to operate the bottomhole pump.

- **Wellhead**, which is the structure installed at the top of the wellbore used to manage the pressure and flow of the well.

- **Packers**, which provide a seal between the outside of the tubing and the inside of the casing, thereby isolating the perforated (producing) zone of the well from other formations. They also provide support for the tubing.

[1] A PCP is used in wells where the oil is viscous. This pump works on much the same principle as an auger bit. It is basically a screw conveyor where the viscous oil is pushed through the pump and up to the surface. An ESP is run on the end of the tubing with an electric cable down the outside of the tubing. A shaft from an electric motor in the submersible unit is jointed to a high-speed centrifugal pump which forces the fluid past the impeller blades of the pump into the tubing and up to the surface.

SIMPLIFIED DIAGRAM OF AN OIL WELLBORE



III. Application of IFRS Guidelines to Well Workovers

IFRS is an international set of standards for accounting issued by the International Accounting Standards Board. The standards are principles-based, rather than rules-based, and thus are intended to provide a framework for analyzing how particular accounting items should be reported.

For entities reporting under IFRS, the IFRS standard providing guidance for the classification of workover costs is International Accounting Standard ("IAS") 16, *Property, Plant and Equipment.* IAS 16 does not expressly reference workover costs or any costs specific to the oil and gas industry. Instead, IAS 16 provides a general framework for assessing when repair and maintenance costs are to be recognized as part of the carrying cost of an item of Plant, Property & Equipment ("PP&E") and when those costs are to be expensed.

Under IAS 16, PP&E is recognized when the cost of an item can be reliably measured, and it is probable that the entity will obtain future economic benefits from the item which extend beyond a single period. PP&E is measured initially at cost, which includes the fair value of the consideration given to acquire the item and any directly attributable costs of bringing the item to working condition for its intended use. Directly attributable costs may include the cost of site preparation, delivery, installation costs and relevant professional fees. Subsequent expenditures relating to an item of PP&E are capitalized if they meet the recognition criteria described above.

Broadly speaking, IAS 16 provides that costs which can be characterized as the "day to day servicing" of an item of PP&E—in other words, routine maintenance—are to be expensed, while more significant repairs or replacement of constituent parts are to be capitalized. In respect of workovers, that basic dividing line was acknowledged in informal guidance issued in 2012 by an Oil and Gas Industry Task Force on IFRSs created by, among others, the Canadian Institute of Chartered Accountants (CICA). Similarly, a practice guide published by the International Financial Reporting Group of Ernst & Young LLP provides that workover costs "that relate to the day-to-day servicing of the wells (i.e., primarily the costs of labour and consumables and possibly the cost of small parts)" are to be expensed, while "costs incurred to restore a well to its former level of production should be capitalized under IFRS."

Obviously, as noted in a practice guide issued by Deloitte & Touche LLP, there can be room for debate as to whether particular workover costs are best characterized as routine maintenance or capital maintenance. Nonetheless, there is broad consensus within the oil and gas industry that some forms of workover costs (such as, for example, the rebuilding or replacement of a bottomhole pump) are capital in nature while others (such as, for example, a routine flushing of sand from the wellbore) are expense in nature. There is also broad consensus within the oil and gas industry that the service costs and any overhead costs associated with major repairs or replacements of downhole equipment are likewise capital in nature.

As noted above, IAS 16 requires that any material replacement of an asset's constituent parts is to be recognized as PP&E (with an accompanying derecognition of the replaced part), if it is expected to confer future economic benefits beyond a single period. Accordingly, there is broad consensus within the oil and gas industry that the replacement of bottomhole pumps and casing is capital in nature. Additionally, although the dividing lines vary among operators as to what constitutes a material replacement, there is likewise broad consensus within the oil and gas industry that a material replacement of tubing or sucker rods is capital in nature.

Some accounting firms have taken the view that the breakdown of a pump, for example, represents a “premature” failure, and therefore, their replacement provides no future economic benefits and should be categorized as an operating expense. There are several reasons why this view is incorrect.

To begin, while it is certainly true that replacing a significant part of an asset which has reached the end of its useful life is one example of a cost that is capital in nature, IAS 16 does not require that a part have reached the end of its useful life in order for its replacement to be recognized as capital. Instead, the test to be applied is whether the replaced part will provide future economic benefits beyond a single period.

Botthomhole pumps easily satisfy that test. A bottomhole pump is a major piece of complex downhole equipment which is used in applications where higher volumes of fluid must be pumped. The replacement or rebuilding of a bottomhole pump is therefore not at all analogous to the replacement of a minor part in a wellbore. It is, instead, the replacement or rebuilding of a significant piece of equipment needed to restore or improve a well’s level of production. Additionally, even in adverse field conditions, the replacement or rebuilding of a bottomhole pump can be expected to provide future economic benefits beyond a single period.

At the same time, however, it is the rule rather than the exception that bottomhole pumps will need to be rebuilt or replaced over the life of a well. That is so because bottomhole pumps have a limited life, particularly in sour or sand-contaminated service. As a result, the cost of the initial pump typically does not represent the total expenditure required for pumps for the life of the well.[2] Pump sizes also need to be adjusted periodically to account for changing flowrates.

Furthermore, while it is irrelevant for purposes of assessing whether IAS 16’s capitalization criteria have been met, it should be noted that the determination of whether a pump failed prematurely is difficult to ascertain. The projected life of a bottomhole pump is highly variable and dependent on the operating conditions to which it is subjected. As a result, while there could be an expectation about the outer limits of how long a pump will last in a particular well, few if any engineers would claim the ability to reliably predict how long a pump will in fact last.

An operator cannot reasonably be expected to anticipate and purchase beforehand all of the pumps which a well is likely to need over the course of its life. Degradation in storage, changes in technology, and unknown sizing requirements all make that course of action impractical. As a result, it is common industry practice for replacement pumps to be purchased as needed, and for those pumps to be included in the carrying cost of the well, just as they would be if they had all been purchased at the time the well went into production.

Additionally, where it is not practical to replace a pump because it may not be possible to obtain one with the proper specifications in the time required, it is commonplace to rebuild the pump by reusing the pump body and replacing the internal components. It is likewise commonplace, and fully in keeping with IAS 16, to capitalize those rebuilding costs in view of the fact that the work is not routine maintenance, but instead the rebuilding of a significant component which is necessary to a well’s productive capacity, and which can be expected to provide future economic benefits beyond a single period.

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[2] For that reason, even companies reporting under GAAP—which, unlike IAS 16, requires an assessment of whether the replaced part results in a “betterment” of the well—typically capitalize replacement pumps, even when they are like in kind to the original unit.

IV. Conclusion

The replacement of significant and material downhole equipment satisfies the capitalization criteria described by IAS 16, and their designation as capital costs is consistent with common practice in the oil and gas industry.

About the Author:
Katrina LaRocque is the president of Petrotech Consulting Services Ltd., an international company which provides accounting, audit and advisory services to the oil and gas industry. Ms. LaRocque has written numerous articles, papers and essays related to oil and gas accounting and has lectured on various industry matters.