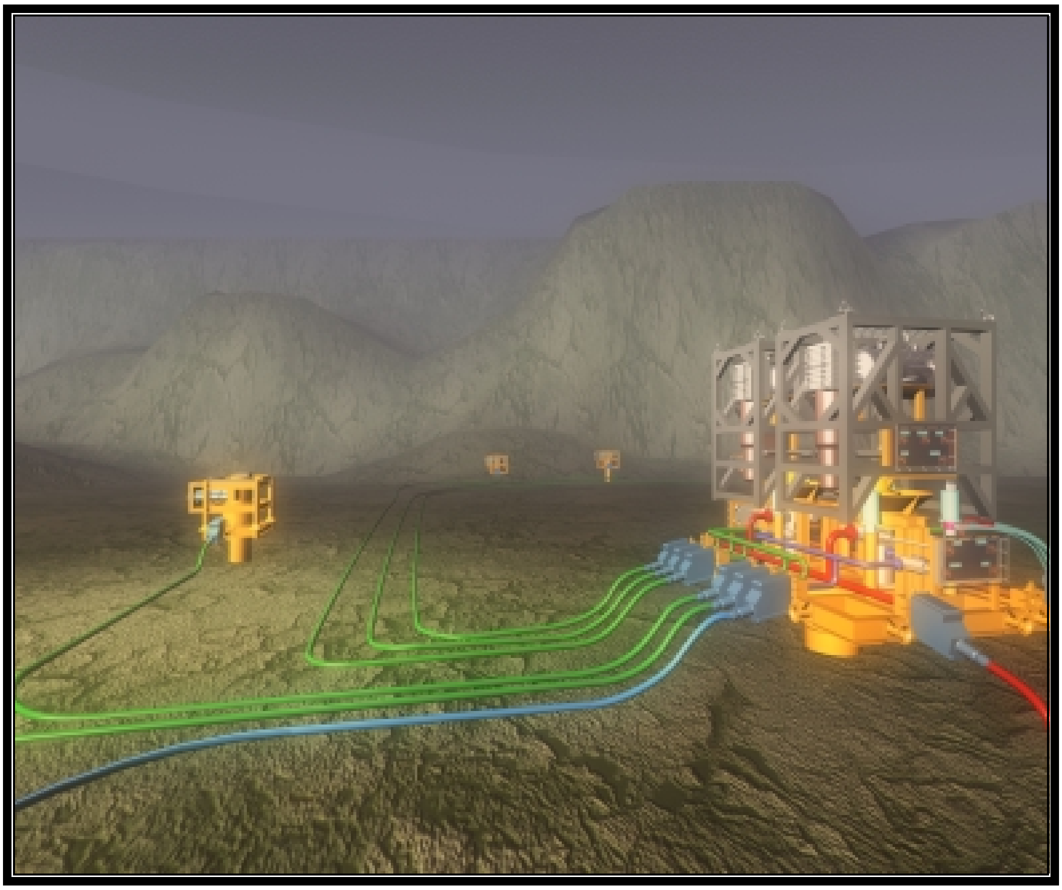
SYSTEM MODULARITY MAKES LONG TIEBACKS AN ECONOMIC OPTION



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Introduction

The principal factors governing the use of long subsea tiebacks largely represent an economic compromise. They are a careful financial juggling act involving the likelihood of operational problems faced by their operators and the cost of resolving them against the significant cost savings that become available through using fewer surface hosts.

This paper will explain that such a compromise is no longer necessary. Seabed processing using System-Modular installations is now available to eliminate many of the technical difficulties faced by operators. The removal of these obstacles liberates the operator so that he can make a decision about whether or not to use long tiebacks and remain confident that his judgement has not been clouded by the uncertainty that comes from technical compromise or weakness.

Alpha Thames has already proved that seabed processing using System-Modules can introduce financial benefits for almost all offshore operators. Whereas, separation systems are of particular interest where there are long-distance tiebacks, it should be noted that the System-Modules can accommodate a great variety of systems and equipment, such as boosting, manifolding, HIPPS (High Integrity Pressure Protection System) and gas compression. The company believes that these benefits are significantly increased when used for long tiebacks and that they are a logical and practical application of existing technology in a forward thinking application.

This paper will explain why.

Seabed processing using System-Modularity

The idea of seabed processing is not new. Its potential benefits were recognised more than 30 years ago when it was noted that a substantial percentage of the material being produced from subsea wells was unwanted. Oil was being pumped to the surface that could also contain gas, water and solids such as sand. All of these would have to be separated from the oil and disposed of before it could be exported from the offshore platform. This has never been regarded as technically difficult although it has always been seen as wasteful in relation to the production pipeline capacity occupied by the unwanted phases.

Twenty years ago, when offshore wells were in comparatively shallow water, this was not a major problem. However, as the industry moves into increasingly deeper water, the economics and the logic are less satisfactory. The concept of pumping unwanted gas and water through long pipelines and expensive risers many thousands of feet to the surface just so that it can be separated, flared or re-injected is a practice that would be inconceivable in any other business. Every industry on the planet, whether it is timber production or gold mining, works on the principle that waste products are removed as near to the source as possible so that expensive transportation resources are not used on materials with no commercial value. This principle is equally as applicable for the oil industry. Risers and long tiebacks are expensive so there is no logic in using them to carry freeloaders.

The obvious location for a seabed processing installation is the vicinity of the wellheads. Downhole separation takes the principle to its logical conclusion but, for the foreseeable future, this can be beset with technical difficulties that can make it expensive and impractical. If the wellhead area is, therefore, acknowledged as the closest practical site for seabed separation, the next choice centres on the design of the separation plant.

To state the obvious; the seabed is not a platform. It is wet, it is difficult to work on equipment and it can be expensive to maintain. These factors must govern the design of any seabed installation and, after years spent studying the problem, engineers at Alpha Thames have concluded that System-Modularity offers the only practical solution.

Let us consider for a moment the alternative of taking a separation plant from a platform and putting it on the seabed. There would obviously be design changes needed that take account of water pressure, ROV accessibility and so forth. Yet fundamentally one arrives at a reasonably complex structure consisting of numerous individual components designed to work together so that water or gas can be separated from the oil when it emerges from the reservoir. This is fine until a component fails – as we all know it will eventually. The operator must then shut down the well, identify the faulty component, charter a DSV, send down an ROV and recover the component. If he is lucky, it will be possible to replace the component on the same trip but we know from long experience how difficult it can be to successfully install equipment on the seabed. Electrical connections may not work, seals may leak and even if the numerous wet-mateable interfaces that exist in such a structure are successfully joined, there is the ever-present possibility of discovering that the fault did not lie with this component in the first place. And do not forget that while all this has been going on, the well has been shut-in and has been earning nothing.

The solution identified by Alpha Thames is known as AlphaPRIME™ and is termed System-Modularity. In essence, this consists of two identical System-Modules each of which contains all the pumping, separation, power and control functions needed to ensure that only the valuable hydrocarbons are transported to the host. The components in the module are not out of the ordinary. They are standard units tried and tested by the industry and assembled in a configuration that fits within the System-Module and meets the needs of that individual field. The important difference between a System-Module and the seabed installation described earlier is that the complete process System-Module is produced as a stand-alone machine that can be thoroughly tested before it is installed, and later recovered for reconfiguration, maintenance or repair. It is of equal importance that while this is happening its partner unit is maintaining well production.

Water separated at the System-Module may be re-injected directly back into the well or the reservoir or discharged in any other appropriate manner. Gas lift may be provided by re-injecting separated gas into the well reducing the density of the produced fluid which then flows more readily up to the wellhead. The gas may then be separated and re-injected, so that a continuous flow is obtained. Alternatively, the gas may be injected into the reservoir via an injection well. If there is sufficient gas, it can be transported to the nearest suitable infrastructure, be it a host platform or a pipeline. In many cases, there is sufficient pressure in the processing system for the transport of the gas. However, with the long tiebacks now envisaged, it is necessary to incorporate gas compressors. Alpha Thames have discussed this with compressor manufacturers; gas compression on the seabed is a realistic prospect within the fairly near future.

Similarly, separated water may be cleaned and re-injected into the reservoir or, in the future, may be cleaned to a higher standard and then jettisoned into the sea. The System-Modules can accommodate the water re-injection pumps and the cleansing and monitoring equipment. Similarly, sand separation and handling equipment can be accommodated.

The separated oil is boosted to the host facility or nearest suitable infrastructure by means of an electric pump running at a constant speed. This avoids the need for expensive speed control equipment that is usually heavy and bulky. The pump can be selected to run at its most efficient speed, thus maintaining reliability. Fluid levels in the separator are continuously monitored and adjusted as necessary by modulating valves that are fitted with electric actuators. The actuators have been developed and thoroughly tested by Alpha Thames.

All the equipment in a typical System-Module is electrically powered and controlled. This makes it highly appropriate for long tiebacks, especially in deepwater, where hydraulic systems would be far less reliable. As all the pumps, separation equipment, power distribution and control equipment are housed within the System-Module, they are accessible for maintenance or, as with all other aspects of the unit, available for any modifications that become necessary as the characteristics of the field change with time.

The development of a field, using an AlphaPRIME™ CPU (Central Processing Unit) equipped with System-Modules, begins with the installation of a simple Docking-Manifold on the seabed, usually on a monopile in the vicinity of the production wells. It can be connected to the wells directly or, in the case of a retro-fit, via an existing manifold facility. The pipelines, flowlines and umbilicals are all connected to the Docking-Manifold and these connections remain undisturbed even during IMR operations. The pipeline and flowline connections are made by any proprietary connection system.

The Docking-Manifold does not include controls or actuated valves and, in a “green field” scenario, it can be installed at the same time as the pipelines. Electrical power is supplied via an ELEx Connector (although any high power, wet-mateable connector can be utilised), and fluid connections for the Docking-Manifold are provided by multibored wellhead type connectors which can, if required, initially be fitted with simple FlowCaps that enable the early flow of first oil. The Docking-Manifold can accommodate two System-Modules that are simply lowered onto it and connected using conventional ROV tools.

An inherent benefit of the System-Module is that its reliability is significantly greater than the “insert retrievable” option described earlier. This is because it has a minimum number of connection interfaces: a multi-bored, wellhead-type fluid connector, high voltage electrical connectors and control/chemical connectors.

Each System-Module weighs a maximum of 50 tonnes dependent upon the specific equipment included. It will have a footprint of only 5 m by 4 m so it can be readily deployed by a suitably equipped conventional support vessel with ROV assistance but without the use of divers within short weather “windows”. Installation and commissioning consequently entails little more than making-up and leak testing the few wet-mateable connections and conducting final functional testing before production begins. Because it has been fully integration tested and “burnt-in” under factory conditions, early life failures are avoided and maximum reliability is assured.

A typical AlphaPRIME™ developed field of say 40,000 BOEPD would use two System-Modules, both of which would operate continuously so that there are no problems associated with starting up dormant equipment. If one System-Module has to be removed for any reason such as planned maintenance or reconfiguration, the remaining System Module will continue to function. Both Modules would have a capacity of 20,000 BOEPD and for larger fields multiples of 20,000 BOEPD modules would be employed. This method has been shown to be the most cost-effective way of ensuring maximum production throughput whilst any one of the System-Modules is retrieved for upgrading or maintenance.

The content and capacities of the System-Modules can be varied at the design stage to suit the client's requirements. For an application using two System-Modules each one would normally be sized for 60 per cent of peak throughput, i.e. the system could handle 120 per cent of peak flow. As the maximum peak throughput would only be for a short period of the overall field life, this would allow a minimum of 60 per cent of peak flow to be maintained during System-Module change out without shutting in any of the production wells. Again, because the maximum peak throughput would only occur for a comparatively short period, each System-Module would have the capacity to process up to 100 per cent of the total throughput during most of the field life.

What System-Modularity means to the economics of long tiebacks

Having arrived at a reliable and fully functional seabed separation process it becomes appropriate to look at the contributions that it can make to long tiebacks both in terms of their economics and also to the logic and common sense of a project's design.

The most obvious economic benefit arises from the fact that the tieback will only be carrying the required hydrocarbons. This has a direct impact on the cost of the pipeline, as it will be possible to install a smaller diameter tieback while achieving the same level of productivity. The hydrocarbons are transported by means of pressure boosting, utilising subsea pumps and/or compressors.

On fields where a well might be subject to unexpected increases in pressure, the System-Module also makes it possible to install a HIPPS (High Integrity Pressure Protection System) adjacent to the production wells. This is significantly more valuable than installing it on a platform or other remote location as, being close to the pressure source (reservoir), it is available to protect the entire system. The safety benefits of this are obvious but the economic advantages for long tiebacks are also significant. By eliminating the need to design a pipeline that is capable of withstanding a worst-case pressure scenario, the operators will benefit from a dramatic reduction in capital costs. It is, of course, impossible to put a figure on the amount that this will save as every situation is different but the savings over many kilometres of pipeline are likely to be significant. As well pressure diminishes with time and the HIPPS is no longer considered necessary, its installation in a System-Module makes its recovery, from the CPU, and replacement simple; it may even be used again elsewhere.

The benefits of seabed separation can also have a major influence on the chemical processes that take place within a long tieback. The most notable of these is that separation of oil, gas and produced water will reduce the propensity for the formation of hydrates and slugging within the pipeline. This will have a direct impact upon the cost of chemicals and may well improve the productivity of the pipeline which can, in turn, impact upon its overall cost effectiveness. With long tiebacks, heat loss and the presence of water would create a problem. Separating the fluid phases is far more effective than heating the pipeline.

Because a System-Module can be designed to accommodate almost any requirement, its capabilities include the option of providing chemical injection. Demulsifiers can be added into the process system and thence into the long distance pipeline thereby avoiding the possibility of aged emulsions at the host.

The final, and most obvious benefit to the chemical processes within a pipeline arises from the removal of water from the produced fluid. This can result in a dramatic reduction in corrosion within the pipeline and will significantly reduce the cost of the pipeline and the cost of installing it. This is also beneficial when exporting gas. Pressure lost during this process may be restored by compressors in the System-

Module making it possible to export the gas over a considerable distance, via a pipeline of significantly reduced diameter, without resorting to the installation of local surface platforms and without suffering from high levels of pipeline deterioration.

Conclusion

The economic success of any long tieback will be influenced by a wide range of factors but we have shown that a major element of these will be the purity of the hydrocarbons that are being passed through it. The use of seabed separation becomes a logical choice as it eliminates many of the problems associated with multi-phase transportation over significant distances. When a field is located in deepwater the need for seabed separation becomes even more apparent regardless of whether long tiebacks are used or not.

Despite the benefits, which have been acknowledged for many years, the offshore oil and gas industry has been slow to adopt seabed processing. This is mainly due to the fact that the conventional wisdom of installing “insert retrievable” components is recognised as having many serious shortcomings. However, the specific engineering challenges faced when working in deepwater require a different way of thinking and we believe that AlphaPRIME™ provides the solution. It permits new technology to be utilised without the normally associated risk because the System-Modules contain fully tested integrated systems operating at the optimum of their reliability curve.

Early life failures (reference: the typical “bathtub” curve) are identified and eliminated during the factory integration testing and “burn-in”. Failures, that would normally be experienced during the wear-out phase near the end of equipment life, are eliminated by changing out the System-Modules as soon as incipient failure is detected; as the System-Modules are electrically powered and controlled, the equipment is continuously, real-time, monitored during its reliable life phase.

This is the ideal solution in a location that is difficult and expensive reach and it provides the reassurance that comes from using a future proof system that can adapt to the changing needs of a field and its operator. It also brings a range of other benefits unrelated to long tiebacks that have not been discussed here but which can be demonstrated on the AlphaPRIME™ System-Module that we have built in Sweden and which is available for inspection and demonstration. It is our belief that System-Modularity is the only logical solution to many of the technical challenges encountered with the use of long tiebacks and it can make a major contribution to the economic success of such a project.

Dockside demonstration of the prototype AlphaPRIME™ System-Module

In-water demonstration of the prototype AlphaPRIME™ System-Module

