Recommended Special Case Royalty Relief Discount Rates for Deepwater Oil and Gas Projects Using Subsea Tiebacks Requiring Enhanced Flow Assurance Technologies

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Table of Contents

Summary

In November 2019, the Bureau of Ocean Energy Management (BOEM) published a comprehensive report on the appropriate discount rates to use in Special Case Royalty Relief (SCRR) applications for Gulf of Mexico (GOM) shallow water oil and gas projects, *Recommended Discount Rates and Policies Regarding Special Case Royalty Relief for Oil and Gas Projects in Shallow Water* (BOEM 2019), hereafter referred to as the Shallow Water Recommended Discount Rate paper. Subsequently, the Bureau of Safety and Environmental Enforcement (BSEE) has turned its focus to GOM deepwater areas and the potential for stranded resources. Specifically, BSEE requested that BOEM evaluate resources that can be tied-back to existing infrastructure using subsea tieback technology requiring enhanced flow assurance technologies, such as subsea booster pumps, and recommend appropriate discount rates that could be applied to those projects needing special case royalty relief. Prior to this analysis,

the SCRR discount rate for GOM shallow water was a maximum of 25 percent, while the rate for all other GOM areas was 10-15 percent.[1]

The Outer Continental Shelf (OCS) Lands Act provides that the Secretary of the Interior may develop rules and regulations to provide for the conservation of OCS resources. An advantage that the deepwater GOM has over other international basins is the presence of existing infrastructure which facilitates the development of smaller fields through the use of subsea infrastructure that "ties back" to an existing facility. Subsea tiebacks have proven to be an important technology in the GOM, as they facilitate the development of marginal deepwater GOM resources that are potentially at risk of being stranded because their resource bases are too small to justify standalone infrastructure at current economic conditions. However, there are marginal resources that, given the distance and specific reservoir properties, cannot be tied back using traditional tieback methods and may require enhanced flow assurance solutions, such as subsea boosting, to allow for the tieback. This introduces additional complexities. To compensate for the added risks, developers will require a higher rate of return in order to move forward with these projects.

Further complicating the tieback of these marginal resources that may require enhanced flow assurance technology is the fact that many existing GOM production facilities are nearing the end of their permitted design life. While BSEE can extend the permitted life of facilities and their components as long as engineering and safety parameters are met, once infrastructure is removed, it is unlikely that similar infrastructure will be re-installed in the same location in the future because of the significant costs involved.

In this report, BOEM presents its research and recommendations regarding the appropriate discount rates to use when computing the net present value of cash flows within SCRR applications for deepwater subsea tiebacks requiring enhanced flow assurance technologies, as defined in Section 1.1. BOEM recommends that companies should self-report discount rates, but that BSEE should impose a 20 percent upper bound on reported discount rates for new deepwater oil and gas wells that connect to existing production facilities using subsea tieback configurations requiring enhanced flow assurance technologies. This recommendation was developed using preliminary guidance from BSEE regarding what projects would qualify for the higher discount rate. The requirements and evaluation of a project's qualifications for approval will ultimately be determined by BSEE. However, BOEM's evaluation sets the discount rate only for deepwater wells that will be tied back to an existing facility and require enhanced flow assurance technologies, and not other wells that may be associated with the project. This recommended discount rate policy would allow companies to earn appropriate rates of return for these technologically riskier projects while protecting the government's right to receive fair amounts of royalty payments.

[1] BOEM publishes the discount rate recommendations and other economic parameters on its website: https://www.boem.gov/oil-gas-energy/energy-economics/royalty-relief/royalty-relief-information.

Chapter 1: Introduction

Section 1.1: Project Background

BOEM sets royalty rates for oil and gas leases in federal waters. Fiscal terms are set on a sale-by-sale basis and have been adjusted over the years. Both shallow and deepwater leases have historically been issued with royalty rates of 12.5 percent, 16.67 percent, and 18.75 percent. For leases issued from sales held in years 1996 through 2000, Congress provided for royalty suspension volumes (i.e., specified volumes of royalty-free production) in the Deepwater Royalty Relief Act of 1995 for water depths 200 meters or deeper in order to encourage the growth of deepwater development in the GOM. In 2020, both GOM lease sales included a 12.5 percent royalty rate for leases in water depths less than 200 meters and an 18.75 percent royalty rate for leases in water depths of 200 meters or more.

Royalties help ensure the public receives a fair return for the development of OCS conventional energy resources. However, situations can arise in which companies are unwilling to develop certain oil and gas resources at the prevailing royalty rate because doing so would not yield a sufficient rate of return to be considered economic. In these situations, an operator may apply for certain types of royalty relief.[2] BSEE administers discretionary royalty relief programs using the economic parameters outlined by BOEM.[3]

Operators of existing leases may apply to BSEE to obtain SCRR under 30 CFR 203.80 for certain oil and gas development activities. When analyzing SCRR applications, an important consideration is the extent to which royalty relief would make the project viable by shifting it from being uneconomic while paying lease-stipulated royalties to economic with royalty relief. Therefore, reviews of SCRR applications generally include estimates of the profitability of the project with and without royalty relief. A key component of these determinations is an interest rate (or discount rate) used to compute the net present value (NPV) of expected cash inflows and outflows. A discount rate accounts for the time value of money, as well as the uncertainty associated with future cash flows. In general, the higher BSEE sets the discount rate, the more royalty relief would be required to make a particular project profitable. The appropriate discount rate should facilitate the development of oil and gas resources by recognizing the risks of a particular project and of stranding publicly-owned resources, while still providing fair market value to the government.

Significantly more exploration and development occurs in the federal deepwater GOM region than the shallow water region and, unlike in shallow water, significant resources remain in the GOM deepwater area and it remains attractive for bidding and exploration (IHS Markit 2018). However, smaller deepwater resources may not be profitable to develop. Even as technology improves, making these smaller resources accessible at lower costs, they are likely to be bypassed in favor of larger or more lucrative resources. Therefore, such marginal resources may remain stranded.

[2] More information regarding royalty relief programs is available at: https://www.boem.gov/Royalty-Relief-Information/ (BOEM 2020).

[3] The royalty relief division of duties between BOEM and BSEE are described in the Royalty Relief Memorandum of Agreement, available at: https://www.bsee.gov/sites/bsee.gov/files/interagency-agreements-mous-moas/deepwater/moa-2011-royalty-relief.pdf. The economic parameters are those referenced in footnote 1.

To conserve deepwater marginal resources that would otherwise likely be stranded, as well as extend the useful life of existing GOM infrastructure with idled capacity, these resources can be tied back to existing facilities. However, given distances and specific reservoir properties, some of these subsea tiebacks may require enhanced flow assurance technologies. These complex systems entail risks, such as cost variability and the risk of operational problems, that increase with the tieback length. As such, a higher rate of return may be required to make these marginal projects economic.

BSEE asked BOEM to research the discount rate used in SCRR evaluations for projects including subsea tiebacks that require enhanced flow assurance technologies. In this context, a project would consist solely of any new deepwater development wells (project may also include exploratory wells) connected to an existing production facility using a subsea tieback requiring enhanced flow assurance technologies, even if, from the company's perspective, it was part of a larger, existing project. BSEE suggested that the SCRR program with the correct discount rate could be effective in preventing the stranding of resources, which is described in more detail in Section 3.6. (project may also include exploratory wellsor development)

More specifically, for the purposes of this analysis, "deepwater subsea tiebacks requiring enhanced flow assurance technologies" refer to connections of new wells to existing production facilities that meet the following criteria: (1) there is no closer facility to which the operator has access that can be efficiently utilized; (2) all wells in the project require subsea enhanced flow assurance technology for optimal recovery, as defined and verified by BSEE (for example, subsea pumping); (3) the subsea enhanced flow assurance technology must already be extant (e.g., it cannot be part of a research project); and (4) the water depth at the well location must be greater than 650 feet (200 meters), such that the well(s) must be in deepwater, but the host facility could, in theory, be located in shallow water. Throughout the remainder of this paper, the phrase "deepwater subsea tiebacks requiring enhanced flow assurance technologies" or "deepwater subsea tiebacks requiring EFAT" shall refer to this definition ("EFAT" being shorthand for "enhanced flow assurance technologies").

This paper provides BOEM's research, analyses, and recommendations regarding the appropriate discount rates to use when evaluating SCRR applications for deepwater subsea tiebacks requiring EFAT, as defined above:

- Section 1.2 shows how alternative discount rates can affect the NPV of an oil and gas project;
- Chapter 2 describes subsea tieback and flow assurance technology and how it can be used to address the unique challenges of each project;
- Chapter 3 provides a theoretical framework for determining and understanding the appropriate discount rate and then focuses the framework on the case of marginal resources accessed using deepwater subsea tiebacks requiring EFAT;
- Chapter 4 describes the available data regarding discount rates;
- Chapter 5 provides BOEM's analysis regarding the appropriate discount rate, with Section 5.1 outlining BOEM's recommendations and Section 5.2 describing important considerations for its implementation; and

- Chapter 6 summarizes BOEM's findings and recommendations.

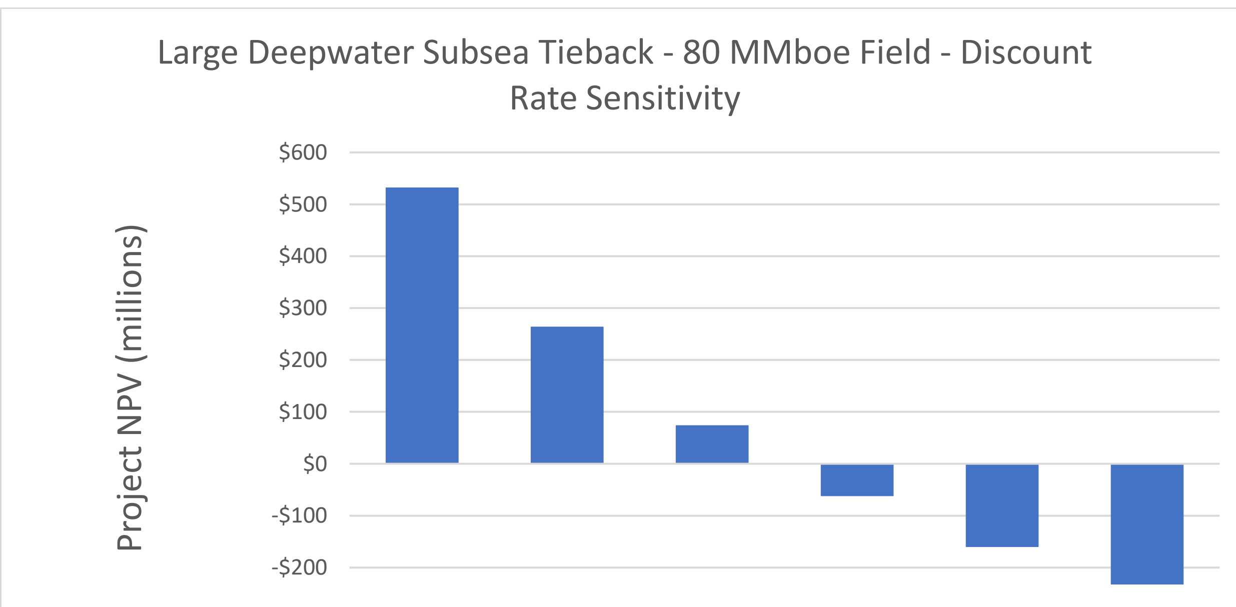
Section 1.2: Numerical Illustration of Discount Rates Impacting Net Present Value

Discount rates have significant impacts on oil and gas project evaluations. This section presents a numerical example of how discount rates can affect profitability, which informs the analyses in subsequent sections.

$$NPV = \sum_{t=1}^{T} \frac{Expected\ Cash\ Flows}{(1+DR)^t} \qquad \text{(Equation 1)}$$

In Equation 1, NPV is computed by applying a discount rate (DR) to expected cash flows in each time period (t), and then summing the values for each time period. Figure 1 displays the NPV of a hypothetical 80 MMboe (million barrels of oil equivalent) deepwater subsea tieback project using discount rates ranging from 5-30 percent. As the discount rate increases, the NPV of a project decreases. Therefore, as higher discount rates are applied to cash flow analysis, more royalty relief would typically be required to change the project's NPV to zero. For the sample project in Figure 1, a five-percentage point change in the applied discount rate can change the project NPV by hundreds of millions of dollars, all else being equal. Though this 80 MMboe tieback represents a larger tieback, the results would be similar regardless of project size.

Figure 1: Example Regarding Discount Rates and NPVs



	5%	10%	15%	20%	25%	30%
NPV with 18.75% Royalty	$532	$264	$74	-$62	-$160	-$232
Royalty Rate*	18.75%	18.75%	18.75%	14.08%	4.39%	0.00%
Lifetime Royalties (millions)	$621	$621	$621	$484	$199	0

*Royalty rate at 20 percent and 25 percent discount rates is the reduced royalty rate required to make this project economic (with an NPV of 0). With a 30 percent discount rate, this project is not economic with any amount of royalty relief.

Royalty relief is granted in the amount necessary to result in a project becoming economic, or more precisely, to have a zero NPV at the designated discount rate. A higher discount rate will generally reduce the NPV of an oil and gas project and require a larger amount of royalty relief to make the project economic. However, there is a limitation on the extent to which royalty relief can offset a negative NPV. At very high discount rates, reducing the royalty rate, even to zero percent, may not be sufficient to bring a project NPV to zero. For the hypothetical project in Figure 1, the project has a positive NPV at 5 percent, 10 percent, and 15 percent discount rates, making it ineligible for royalty relief by regulation. If a 20 percent or 25 percent discount rate is applied to the project with a royalty rate of 18.75 percent, the project would be uneconomic and would necessitate royalty relief. If the project were evaluated with a 20 percent discount rate and royalty relief were provided in the form of a reduced royalty, the royalty would be reduced to 14.08 percent, making the NPV zero. If it were evaluated with the 25 percent discount rate, the relief would be granted by reducing the royalty rate to 4.39 percent. At a 30 percent discount rate, a royalty rate of 0 percent would not be enough to make the project economic (with a 0 NPV). For this example, the hypothetical maximum discount rate that could be used to provide royalty relief to the project would be 27 percent, as it generates a zero NPV with a reduced royalty rate of 0 percent.

Given that revenue and expense forecasts provided by operators are verified by BSEE, royalty relief is provided in the precise amount required to change the NPV of a project from negative to zero NPV. This highlights the importance of applying an appropriate discount rate that allows BSEE to assess whether royalty relief is necessary and if so, to grant an amount of relief that allows a company to earn an appropriate rate of return (while protecting the government's right to receive fair market value from royalty payments). BOEM provides the discount rate as a range, or up to a maximum rate, so that companies can self-report the discount rate at which they would like their project evaluated.

Chapter 2: Subsea Tieback Technology

Generally, a subsea tieback refers to an offshore oil and gas production system designed to move hydrocarbons produced from a subsea well or field of wells over some distance before being lifted to a central fixed or floating surface production facility. They are an alternative solution for gathering production, enabling operators to avoid additional satellite surface infrastructure. It is not a new approach; the first subsea wellhead in the GOM was installed in 1961. However, without additional subsea processing equipment, tieback distances are constrained because flow complications arise over longer distances as the hydrocarbons travel en route to the processing facility. This distance limitation can and has been overcome with additional subsea component technology and strategies. The ability to gather production over extended distances is an attractive strategy for developing discovered, but otherwise marginal, resources (i.e., those that do not meet the criteria for a standalone development), and extending the useful life of existing GOM infrastructure with idled capacity.

Installation and startup of these systems are generally more complicated than installation and startup of conventional facilities. All the components are on the seafloor, requiring service vessels with sufficient crane and ROV capabilities and operators with the relevant expertise. Because the components are generally less accessible once on the seafloor, they are engineered to be more robust and may be designed with modular components and production redundancies so that problems can be isolated and they can remain online in the event of a component failure. Other challenges, such as physical damage due to buckling and spanning for flowlines traversing varied topography over long distances, and infrastructure movement due to thermal cycling, can generally be mitigated in the design but must be monitored over time. Significant downtime can occur during installation or production if redesigned or replacement parts need to be engineered and fabricated. Once operational, the system should require minimal direct intervention, with the operator relying on remote monitoring and interaction with the various components.

Conventional tiebacks generally rely on the native reservoir pressure to produce the oil and gas back to the processing facility. Due to this reliance, the flow distance is physically limited; conventional tie-back distances are highly dependent on the specific properties of the reservoir and its fluids. Produced fluids are not a single homogeneous chemical composition, but a mixture of different hydrocarbon compounds with properties and phase behaviors that change at varying pressures and temperatures. At high reservoir pressures and temperatures, compounds that are normally solid at standard conditions flow as a liquid and those which are normally gaseous are dissolved into the hydrocarbon solution. After exiting the well, these hydrocarbons travel through the subsea flow line, and begin cooling as they are exposed to the low temperature environment of the sea floor. The result of this pressure and temperature decline can lead to changes in some of the hydrocarbon phases, which will often cause hydrate formation, wax deposits, or other solid deposits within the flow line. Shorter tieback distances are able to produce their fluids prior to significant formation of these deposits. However as distances increase, these complications along with multiphase fluid flow instability (aka, slugging) can introduce serious flow assurance challenges.

Industry has, in large part, developed technologies[4] and strategies to overcome these flow assurance challenges. Rather than a single approach, however, these solutions are engineered on a case-by-case basis and generally consist of a combination of technologies used in concert to solve the specific challenges the tieback system is presenting. Though not currently considered proven for use in the Gulf of Mexico, these technologies can include electrically-heated pipe and improved flow line insulation materials to improve thermal performance. Configuring the subsea lines and manifolds with looping capabilities can also be an effective strategy to maintain fluid flow in the system during a production shutdown. Despite these, chemical injection and improved pipeline scraping (aka, pigging) capabilities may still be necessary in some cases to preserve fluid flow. Ultimately, deploying subsea oil and gas separation (subsea processing) may be preferable, as it may address many of the fluid complications early in the production system, before they become an operational problem. However, this approach requires significant additional subsea components, including robust production-handling manifolds and fluid pumping and gas compression capabilities. The subsea system must also have reliable monitoring capabilities, so the operator can effectively manage the various system componentry. Additional considerations must also be given to the host infrastructure, which must be able to support the power, storage, and communication needs of these

[4] The technologies in this chapter are discussed generally and BSEE may or may not consider them proven for use in the United States. If BSEE chooses to implement a SCRR program for deepwater subsea tieback projects with EFAT, operators should defer to BSEE guidance that specifically outlines the acceptable technologies, strategies, and cost requirements necessary for a project to qualify.

system elements, particularly the electrical power requirements for any subsea gas compression and fluid pumping equipment, which can be significant. This becomes further complicated as distances and water depths cause those needs to grow.

Tieback projects which implement some or all these strategies may not be turnkey and could require additional fine-tuning to balance the multiple components of the system to stabilize production within a sustainable operational envelope. Additionally, the production fluid properties may change over time as the reservoir draws down, necessitating further adaptation. Finally, production shutdowns for any reason can cause their own challenges when trying to bring the system of cooled, static fluid back online.

Despite the complexity, subsea tieback systems can be a successful production solution where surface infrastructure is not desired, feasible, or economic. They are particularly attractive in the GOM, where significant areas can be reached from existing surface infrastructure with available capacity using these methods, thereby preventing the stranding of resources and extending the economic life of the surface facilities. Still, they require a thorough understanding of the reservoir fluid properties, and at longer distances require novel technological approaches to implement effectively. At these long distances, performance and reliability may be a source of technological risk and uncertainty for the operator.

Chapter 3: General Discussion of Discount Rates

Section 3.1: Introduction

This chapter provides a theoretical framework for determining and understanding the appropriate discount rates in the context of SCRR applications and describes how various risks faced by deepwater operators targeting marginal resources using subsea tiebacks requiring EFAT influence the discount rate necessary for a company to select a project.[5]

Businesses typically determine which projects to pursue by assessing the size and timing of expected cash inflows and outflows. The timing of cash flows is important because money received sooner is more valuable than money received later. In addition, the owners of businesses prefer certainty and seek to minimize risk regarding the size and timing of cash flows. As the cash flows from oil and gas projects are subject to numerous uncertainties, businesses need a framework for valuing these uncertain cash flows. A common framework is to use risk-adjusted discount rates (RADRs), which entails applying higher discount rates for riskier projects.[6]

$$\mathrm{RADR} = \mathrm{WACC} + \mathrm{IHR} + \mathrm{RA} \qquad \text{(Equation 2)}$$

[5] This paper generally refers to nominal discount rates, which do not remove expected inflation. One can convert nominal discount rates to real discount rates (which do remove expected inflation) as:
Real discount rate = [(1+ nominal discount rate)/(1 + expected inflation rate)] -1
(where all variables are entered as decimals).

[6] An alternate approach is to discount cash flows using a lower discount rate than in Equation 2, and to then to decrease the resultant net present value by a reserve adjustment factor (Society of Petroleum Evaluation Engineers 2020). There has also been some research regarding the use of option theory related to oil and gas projects, but these methods are not often used in practice (Dickens and Lohrenz 1996).

Inkpen and Moffett (2011) decompose discount rates as shown in Equation 2, where:

- RADR: Risk-adjusted discount rate applied to expected cash flows
- WACC: Weighted average cost of capital
- IHR: Incremental hurdle rate
- RA: Risk adjustment

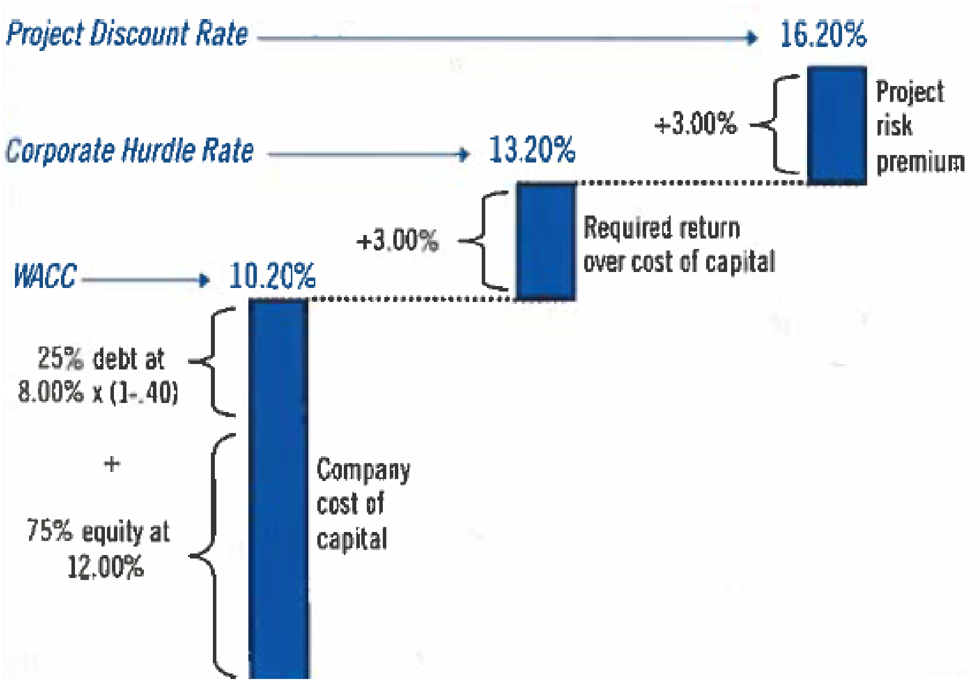
This equation shows that companies will expect to earn at least as much as their weighted average cost of debt and equity capital (WACC). In addition, if companies have multiple profitable investment opportunities (and a limited budget), they will require more than the WACC in order to pursue an average-risk project, which is referred to as the incremental hurdle rate (IHR). Finally, a project, particularly one for which royalty relief would be requested, likely faces additional risks compared to a company's average project. These risk adjustments are project specific, but in general, the probability of profit for any marginal project is more sensitive to variable deviations (such as resource size and prices) from their expected values. This is true for marginal deepwater projects using subsea tiebacks requiring EFAT, as well as other marginal projects.

Additionally, as discussed in Chapter 2, the greater complexity associated with deepwater subsea tiebacks requiring EFAT makes performance and reliability greater sources of risk for operators and these risks generally increase with the tieback length. As a result, marginal resources developed using deepwater subsea tiebacks requiring EFAT will be subject to additional risks due to the technical and economic complexities that require the use of enhanced flow assurance technology in conjunction with subsea tiebacks. Therefore, businesses will likely require a higher discount rate to compensate for these risks.

Figure 2 presents a hypothetical example from Inkpen and Moffett (2011) regarding the components of a risk-adjusted discount rate. In this example, an oil and gas company is analyzing the profitability of a particular project. The company is financed by 75 percent equity and 25 percent debt. If the cost of equity is 12 percent, the cost of debt is 8 percent, and the corporate tax rate is 40 percent, the weighted average cost of capital of these funding streams is 10.2 percent (see Section 3.2 for more information).[7] Due to competing investment projects, this company has an average incremental hurdle rate of 3 percent (and a total corporate hurdle rate of 13.2 percent). Finally, the particular project under consideration is riskier than the company's average project, so the company adds a 3 percent percent risk premium. This yields a total project discount rate of 16.2 percent. Therefore, this company will use a discount rate of 16.2 percent to compute the net present value of cash flows from this project.

[7] The current corporate tax rate is 21%. If this 21% corporate tax rate were applied to the example in Figure 2 (and assuming other variables did not change), the WACC would equal 10.58% (and the project discount rate would equal 16.58%). The WACC would increase because there would be less of a tax shield associated with debt financing (see Section 3.2).

Figure 2: Components of a Risk-Adjusted Discount Rate



Source:Inkpen and Moffett (2011)

Section 3.2: Weighted Average Cost of Capital

The first component in the RADR is the weighted average cost of a company's debt and equity financing, the WACC. A company expects to earn at least the weighted average cost of its debt and equity financing in order to undertake the project. In this circumstance, the project would be low risk (i.e., no RA) and, potentially, one of very few available to the firm if a project's RADR is composed solely of the WACC (i.e., no IHR).

$$WACC = \left(\frac{E}{V}\right) R_E + \left(\frac{D}{V}\right) R_D(1 - T_C) \qquad \text{(Equation 3)}$$

Equation 3 is the formula for the WACC (Corporate Finance Institute 2019), where:

- E: Market value of total equity
- D: Market value of total debt
- V=E+D (the total market value of debt and equity combined)
- RE: Cost of equity
- RD: Cost of debt
- TC: Corporate income tax rate

As discussed in the Shallow Water Recommended Discount Rate paper (BOEM 2019), the first part of Equation 3 is the portion of a company's cost of capital represented by required returns on equity. In particular, equity investors will require a rate of return commensurate with a company's collective risk profile. There are numerous risks associated with oil and gas projects, such as price volatility, uncertainty regarding resources, and variability of input costs. Since investors often can diversify their equity holdings, a common assumption is that equity investors will only receive compensation for risks that cannot be eliminated through diversification.[8] However, given the numerous sources of uncertainty for oil and gas companies, as well as the interdependence between energy markets and the broader economy, many of the risks cannot be diversified away.

The second part of Equation 3 represents the cost of debt financing (since debt interest payments are tax deductible, one considers the after-tax cost of debt financing). One can roughly think of the cost of debt as the sum of a risk-free interest rate, often approximated by the interest rate on a U.S. Treasury bond or bill, plus a premium to compensate lenders for the possibility that some or all of a loan may not be paid back on schedule. U.S. Treasury yields have been low in recent years. However, given the various risks associated with oil and gas development, lenders often require a sizable risk premium.

Both of these components within the WACC equation are different for deepwater subsea projects with flow assurance issues than they are for shallow water projects. First, in regards to the return on equity, companies undertaking deepwater subsea tieback projects requiring EFAT are publicly-held companies, which gives them a greater ability to diversify their risks than companies operating in the shallow water GOM. Therefore, the required return on equity capital for deepwater oil and gas firms is not expected to be as high as for shallow water oil and gas firms.

Similarly, for the second part of the equation, it is likely that companies operating in shallow water have a greater cost of capital due to the riskier nature of shallow prospects, and these smaller-sized companies generally possess less equity, more debt, and fewer assets in their portfolios. This is less likely to be true, however, for larger firms operating in deepwater. Firms that operate in the deepwater GOM are generally large conglomerates with a significant amount of capital, booked reserves, or tangible assets. So, again, one would expect this portion of the WACC to be lower for deepwater companies than for shallow water companies.

Section 3.3: Incremental Hurdle Rate

At any point in time, oil and gas companies are likely considering several potential projects. The minimum requirement for these projects is that they yield a return that is greater than (or equal to) the WACC, assuming there are no risk adjustments necessary. However, in many cases, a company will have multiple profitable projects under consideration. A company may be able to obtain additional funding to pursue more or all of these projects, but to the extent a company is unable or unwilling to do this, the company will apply a framework for deciding which projects to pursue. In the context of understanding discount rates, an appropriate framework is an incremental hurdle rate that represents the rate of return above the WACC that would induce a company to undertake a particular project relative to other projects. This incremental hurdle rate will thus vary through time

[8] This is the core assumption of the Capital Asset Pricing Model, a widely-used framework for determining required rates of return (Sharpe 1964). Other theories of asset prices incorporate additional factors in their models, such as a company's size and the ratio of a company's book equity to its market equity (Fama and French 1993).

given market conditions. For example, given the current low price environment, it is likely that firms have fewer profitable investment projects available to them than they would in a high price environment. It is even possible that some firms may not be willing to take on new projects until prices go up, relying instead on the production of existing projects. Therefore, all else being equal, the incremental hurdle rate will be lower given the low prices currently prevailing because there would be fewer profitable alternatives available.

In practice, many factors may influence oil and gas investment decisions. For example, the size of the project (and the resulting overall profits earned) will be an important factor. Marginal deepwater projects are, by definition, expected to be smaller than other deepwater projects and thus may not be as lucrative, particularly if the projects are mutually exclusive.[9] It is possible that some marginal deepwater projects may never prove profitable enough to induce investment when there are so many other larger or more lucrative resources available in deepwater. Therefore, all else being equal, an average company will require a higher rate of return for a marginal deepwater project. However, the size of the oil and gas company may also affect its incremental hurdle rate. In particular, large companies may require a higher incremental hurdle rate than smaller companies because large companies have more (and larger) investment options. This has resulted in a trend of major oil and gas companies leaving the shallow water GOM to focus on larger projects such as those in the deepwater GOM or elsewhere in the world that offer more potential upside. This further supports the possibility of the large firms that primarily operate in the deepwater GOM permanently bypassing marginal deepwater projects in favor of larger, more profitable projects.

Companies may also choose projects that recover their costs more quickly than other projects. In general, deepwater projects recover their costs more slowly than both shallow water projects and onshore projects, putting them at a relative disadvantage. On the other hand, spillover effects from a particular project to other future projects can influence development decisions. For example, pursuing a particular oil and gas project could position a company to pursue similar or nearby projects in the future through cost efficiencies or technological improvements. Subsea tieback technology is at the cutting edge of innovation in the offshore oil and gas industry. As subsea technology continues to mature, it will allow firms to access resources further from existing host facilities, and more efficiently and inexpensively at any given distance. Additionally, existing subsea tieback structures could potentially be used as part of tiebacks to future wells. In some cases, this could make subsea tieback projects, potentially even deepwater subsea tiebacks requiring EFAT that involve (or are expected to involve, in the case of exploratory wells) marginal resources, more attractive relative to other projects.

Given the various factors discussed above, the extent to which a marginal deepwater project requires a higher or lower incremental hurdle rate than other projects will depend on the unique cirumstances of each project/company combination.

[9] Although, it is possible that some projects expected to be marginal that initially require exploratory wells could instead be larger and more profitable than original anticipated. This cannot be known ex ante, however, only ex post.

Section 3.4: Risk Adjustment

The discount rate for SCRR applications should account for the risks associated with deepwater subsea tiebacks requiring EFAT. Projects that would potentially qualify for royalty relief are, by definition, only marginally economic or uneconomic (due to some combination of limited oil and gas resources and high production costs). Therefore, the likelihood that these projects will be profitable is sensitive to any deviations of economic variables (such as market prices, discovered resources, and development costs) from their projected values.

The risk adjustment considers the uncertainty of the oil and gas resource characteristics, including the size, quality, and costs of extraction. The risk adjustment for deepwater subsea tiebacks requiring EFAT should account for the fact that the marginal resources will require expensive technologies to provide the necessary flow assurance back to host facilities. It should also account for the potential complexity of subsea tieback systems. Compared to shallow water with its small remaining resources, the potential upside to developing a deepwater project is greater. However, the requirements and conditions of the SCRR application process will prevent excessive royalty relief (i.e., more than is truly necessary to make a project economic) from being provided in that event.

Finally, there is an inherent risk with deepwater subsea tiebacks requiring EFAT that increases with length. As discussed in Chapter 2, subsea tiebacks are complex systems that can increase performance and reliability risks, particularly over longer distances. The longer the tieback, the greater the length along which a problem could occur, such as an object damaging the installation. Similarly, greater length increases the risks associated with maintaining flow and the demands on host infrastructure. Additionally, although individual components of a subsea system may be modular, the overall subsea tieback system may be less flexible, particularly more complex systems. System complexity is itself driven, in part, by subsea tieback length. Therefore, when something goes wrong with a deepwater subsea tieback requiring EFAT, there may not be an alternative method to access the production well, increasing the impact of any unscheduled downtime. And, because the equipment is installed primarily on the sea floor, addressing problems can be more difficult and costly.

In summary, the discount rate for deepwater subsea tiebacks requiring EFAT should be adjusted upwards compared to other deepwater projects to account for these risks, yet should be lower than for shallow water projects. The comparisons with shallow water projects have been touched on throughout this section but will be tied together in Section 3.5.

Section 3.5: Shallow Water Comparison

The material presented so far has supported raising the SCRR discount rate for deepwater subsea tiebacks requiring EFAT above the current level for deepwater in general. However, it has also clearly indicated that the appropriate discount rate for deepwater subsea tiebacks requiring EFAT should be lower than the 25 percent rate set for shallow water in the Shallow Water Recommended Discount Rate paper (BOEM 2019).

The type of company operating in shallow water is fundamentally different from deepwater and these differences lead to a different WACC. Companies operating in shallow water differ from those operating in deepwater in two key ways: (1) they tend to be privately-held; and (2) they tend to be significantly smaller. Smaller companies generally possess less equity, more debt, and fewer assets in their portfolios and privately-owned companies are less able to diversify their risks. Both of the factors increase the WACC—(1) requires the return on equity to be higher and (2) requires the return on debt to be higher. Therefore, companies in shallow water require both portions of WACC return to be higher than deepwater firms.

There are competing influences on the IHR. It is possible that marginal deepwater resources may be somewhat more desirable when considering multiple projects than a marginal shallow water project, which has virtually no probability of a large upside return. On the other hand, deepwater projects recover their costs more slowly than shallow water projects and that is generally less desirable to companies. Therefore, it is not entirely clear whether the IHR for deepwater subsea tiebacks requiring EFAT would be significantly different than for shallow water.

The probability of profit due to size of the resource also sets the two types of projects apart, as reflected in the risk adjustment. The probability of profit for a marginal project is sensitive to deviations of variables from their expected values (for example, resource size) regardless of whether the project is in the shallow water GOM or a deepwater GOM project using subsea tiebacks requiring EFAT. However, the possibility of a field being small is much higher in the more mature shallow water GOM, resulting in a higher risk-adjusted discount rate for shallow water than for deepwater subsea tiebacks requiring EFAT.

Based on this, BOEM can conclude that although the SCRR discount rate for deepwater subsea tiebacks requiring EFAT should be raised above the current 10-15 percent level, it should not be as high as the 25 percent rate for shallow water, based on the lower value for the WACC and RA portion of the RADR at minimum. This general understanding is carried into the next Chapter where the available data is presented and discussed.

Section 3.6: Societal Considerations

The analysis of discount rates in prior sections focused on discount rates used by oil and gas companies when making investment decisions. This is appropriate because companies ultimately determine whether to pursue certain projects, and because federal policy regarding this issue has typically focused on the extent to which royalty payments (and the resulting royalty relief) determine whether a project is economic to pursue. However, as discussed in the Shallow Water Recommended Discount Rate paper (BOEM 2019), when considering policy decisions, it is appropriate to consider the costs and benefits of policy options from the perspective of society as a whole. In the analysis of discount rates, a societal viewpoint highlights the effects of oil and gas industry decisions on other actors in the economy. A societal viewpoint also highlights the risks of setting the discount rate too high or too low.

When an oil and gas company undertakes a discounted cash flow analysis in its decision-making process, it does not incorporate numerous effects on society as a whole. Some of these effects are beneficial, such as increased government revenues, lower energy prices, less dependence on substitute energy sources, and less economic inefficiency due to fewer stranded resources. Other effects, such as potential environmental impacts, may be negative (depending on the alternatives). An important issue that is not sufficiently captured in an individual company's analysis is the possibility that marginal resources in deepwater may remain permanently stranded because companies will opt to place limited development resources towards larger or more lucrative deepwater prospects. Additionally, because oil and gas companies are not considering spare capacity at existing facilities, the possible removal of those facilities, or the risk that not using the facilities while they are still operational to access marginal resources, the resources are less likely to be developed in the future.

The OCS Lands Act authorizes the Secretary of the Department of the Interior to issue regulations in the interest of conservation of OCS natural resources.[10] Conservation of OCS resources promotes economic efficiency, and from an economic perspective, it would be preferable for leasing, development, and production activities to be carried out in a manner that increases the net economic value to society from the development of OCS resources.

In the context of marginal GOM deepwater subsea tiebacks requiring enhanced flow assurance development, conservation of resources is a concern because the existing facilities that could host tiebacks are required to be removed at the end of their design life unless an extension is granted, assuming the facility meets engineering and safety parameters. BSEE estimates that 48 percent of GOM average daily oil production from deepwater facilities (facilities in water depths greater than 200 meters) have less than 10 years of remaining permitted design life and that approximately four out of five deepwater facilities are producing at rates less than 50 percent of their daily oil nameplate capacity. Based on that data, BSEE estimates that by 2025, 32 percent of deepwater facilities, representing 24 percent of GOM average daily oil production, are scheduled to reach the end of their permitted design life. Further, BSEE asked BOEM to estimate the contingent resources within 30 to 60 miles of deepwater GOM facilities as these could be targeted by subsea tiebacks with EFAT. BOEM estimates that there are approximately 4.5 billion barrels of oil equivalent (BOE) of contingent resources in this 30 to 60 mile band around existing platforms. Additional information on facility utilization rates is available in Appendix A.

Once infrastructure is removed, it is unlikely that similar infrastructure will be re-installed in the future because of the significant costs involved. Therefore, oil and gas companies, and society as a whole, may eventually lose the option to develop some marginal deepwater resources even if economic conditions become more favorable in the future. To the extent that technology continues to develop toward longer, more efficient subsea tiebacks, more distant facilities could become suitable for tieback. However, in that event, larger deepwater resources would still be relatively more attractive to developers, likely leaving marginal resources undeveloped. Therefore, one can view the determination of discount rates as a policy lever to better account for these societal interests.

It is also important to consider the risks to society of setting discount rates too low or too high. If the government sets discount rates too low, certain projects may not be pursued (that may have

[10] 43 U.S.C. § 1334(a)

been pursued if appropriate discount rates were used) and resources may become stranded. As mentioned previously, society may also lose the value of the option to develop certain marginal deepwater oil and gas resources in the future. If the government sets discount rates too high, it will encourage royalty-relief applications for projects that would have proceeded without royalty relief. Thus, the government could lose royalty revenue. In addition, for very marginal projects, setting the discount rate too high may lead to the conclusion that no amount of royalty relief would make these projects economic, and thus the projects would not be pursued. These effects highlight the need to select discount rates that appropriately balance society's varied interests.

Chapter 4: Analysis of Data Sources for Discount Rates

The discount rates the government uses for evaluating SCRR applications should be similar to the rates companies use when evaluating similar upstream oil and gas investment opportunities. Unfortunately, the discount rates companies use, and the evaluation techniques they employ, differ across companies and are proprietary. There are several methods for estimating companies' discount rates. These methods include (1) measuring the cost of capital from financial data, (2) estimating the average return on upstream oil and gas investments, and (3) surveying companies to elicit their discount rates. There are various data and confidentiality limitations regarding methods 1 and 2. Therefore, this Chapter will summarize the available data from surveys and related reports. Section 4.1 will describe discount rate data from the Society of Petroleum Evaluation Engineers (SPEE). Section 4.2 will discuss other useful data sources. The data sources and data have been re-examined, expanded, and updated where appropriate to reflect new information that has emerged since the Shallow Water Recommended Discount Rate paper (BOEM 2019). Section 4.3 analyzes the entirety of the data presented.

Section 4.1: Society of Petroleum Evaluation Engineers Data

The SPEE conducts an annual survey of their members regarding upstream resource evaluation topics. The survey asks members a wide range of questions, including questions about SPEE member companies' RADRs used for different types of projects. BOEM acquired reports that summarized the data from the 2016, 2017, 2018, and 2020 surveys.[11] The majority of survey responses came from employees of either exploration and production companies or oil and gas consulting companies, whose job functions primarily entail property valuation, reserves estimation, or acquisition and divestiture activities. The surveys do not differentiate between offshore and onshore evaluation methods.

In the 2020 SPEE survey, nearly 81 percent of respondents were located in the United States, and the vast majority of them spent a significant amount of time evaluating resources in the United States. When asked for reasons why RADRs were used to evaluate assets, 78 percent of respondents stated that reserve risk made the use of RADRs appropriate in their evaluations. Other reasons that were cited in over 44 percent of responses include price uncertainty, expense uncertainty, mechanical risk, and political regulatory uncertainty.

[11] BSEE acquired the 2020 SPEE survey on behalf of BOEM.

The 2020 SPEE survey asked members for the actual RADRs used when evaluating projects by the categories of resources they target. As one would expect, the less certainty companies had regarding the volume of recoverable resources, the higher the RADR used to evaluate these projects. Creating asset decline curves and cash flow models is straightforward when the asset being evaluated is proved, developed, or producing. While there is risk involved with any investment decision, the reserve risk is mitigated when companies are more certain about the recoverable resource. This is why proved undeveloped reserves require a lower RADR than probable reserves. BOEM found the discount rate percentage for probable reserves the most applicable for shallow water projects in its Shallow Water Recommended Discount Rate paper (BOEM 2019), but believes that proved reserves provides a better comparison for deepwater resources accessed using subsea tiebacks that require EFAT. This is because there is substantial liklihood that a sufficient quantity of resources exist for deepwater projects that require EFAT. In addition, setting a unique discount rate for subsea tiebacks that require EFAT is a more targeted effort than BOEM's effort to set a general shallow water discount rate. While an operator may occasionally drill an exploratory well for subea tiebacks that require EFAT, BOEM feels it appropriate to develop a discount rate comparison for the primary targets of this policy (reserves that are very likely to exist). Therefore, BOEM used the proved reserves category for comparison purposes. Additionally, as discussed in other parts of this paper, there is strong evidence indicating that the discount rate for deepwater subsea tiebacks requiring EFAT should be lower than for shallow water.

The 2020 SPEE survey results show that the median RADR (the P50 value)[12] used for proved undeveloped reserves is around 20 percent. Similarly, the 2016 and 2017 SPEE surveys found that the median RADR used for proved undeveloped reserves was 20 percent and the 2018 survey shows results that appear to be very close to 20 percent but possibly slightly lower.

A limitation of the SPEE median RADR data is that some of the survey responses relate to RADRs used for purposes somewhat different from oil and gas exploration and development. For example, RADRs are also used for asset acquisitions and overall corporate valuations. The 2017 SPEE survey presented results for the different categories of use (the SPEE data for other years did not provide these breakouts). The 2017 SPEE data found that the mean RADR used for oil and gas field development was 19.5 percent (sample size=24), and the mean RADR used for decisions to drill exploration wells was 17.4 percent (sample size=20). However, there were wide ranges of RADRs used and this would presumably encompass the full range of reserve types.

Section 4.2: Other Data Sources

Limited data is available regarding the discount rates used by oil and gas companies. Apart from SPEE data, most data available comes from Wood Mackenzie, the state of Texas, and other countries.

The Texas Comptroller of Public Accounts (2020) calculates discount rates based on the weighted average cost of capital of 18 petroleum companies. The Texas Comptroller does allow discount rate adjustments for property-specific risk considerations. The average range of discount rates for 2020

[12] The probability that 50 percent of the results will be equal or greater than this result.

was 10.52 percent to 17.79 percent, a decrease from the 2018 rates of 14.62 percent to 20.81 percent. The Texas Comptroller specifies that the discount rate for offshore properties is 2 percentage points higher than the average discount rate, making the range 12.52 percent to 19.79 percent.

Oil and Gas Journal (2018) provides discount rate data from Wood Mackenzie's 2017 and 2018 annual surveys of upstream oil and gas companies.[13] The discount rates for various project categories in 2017 and 2018 were:

- Unconventional projects: 14.0 percent in 2017; 14.1 percent in 2018
- Deepwater projects: 15.9 percent in 2017; 14.8 percent in 2018
- Exploration projects: 15.8 percent in 2017; 14.8 percent in 2018

The Oxford Institute for Energy Studies (2019) emphasizes the risks of oil and gas projects in the context of a long-run transition towards renewable energy sources. This study cites survey results that a deepwater project has an average 18 percent discount rate.

Other countries also use discount rates to help calculate companies' discounted cash flows. The United Kingdom surveyed companies in 2017 and 2018 calculating out a "satisfactory expected commercial return" (SECR). The United Kingdom aims to maximize the expected net value of economically recoverable petroleum. The Oil and Gas Authority (OGA), the U.K.'s regulatory authority, sets discount rates based on the WACC. The current discount rate OGA sets for the U.K. Continental Shelf is between 5 percent and 12.75 percent in nominal terms. The OGA has found this is reflective of companies operating on their Continental Shelf and equivalent to a 10 percent real discount rate.

Section 4.3: Analysis of Available Data

The SPEE surveys (for 2016, 2017, 2018, and 2020) provide the most detailed discount rate data. These surveys report that the median discount rate used for proved undeveloped reserves (the category just below the one used for shallow water) was approximately 20 percent. While informative, some of the survey responses related to discount rates for uses other than oil and gas exploration and field development. The 2017 SPEE survey was the only survey to provide discount rates specifically for these categories. The 2017 SPEE survey found that the mean RADR used for field development was 19.5 percent and the mean RADR used for exploration wells was 17.4 percent, but this likely includes more than just proved undeveloped reserves.

These mean values are roughly consistent with the the rates from the Texas Comptroller (Texas Comptroller of Public Accounts 2018 and 2020), as well as those for deepwater projects cited in the Oxford Institute for Energy Studies (2019). On the other hand, the data from the Oil and Gas Journal (2018) and, particularly, the discount rates cited by the U.K.'s OGA (The Oil and Gas Authority 2015, 2017, and 2018) are much lower than those presented by the SPEE: around 15 percent and 12 percent, respectively, although the latter is for the U.K.'s Continental Shelf.

[13] No data are available for 2019.

Chapter 5: Recommendations

Section 5.1: Discount Rate Recommendation

Deepwater subsea tiebacks that require EFAT have unique characteristics and risks that warrant a somewhat higher rate of return than traditional deepwater projects. These projects entail additional risks associated with both project costs and potential development problems that result from reliance on complex flow assurance technologies. Subsea tiebacks that require EFAT frequently target low- or moderate-sized reservoirs, increasing the economic risk of a project. As the GOM basin matures and the larger reservoirs are developed, the remaining fields become more marginal. Subsea tiebacks utilizing EFAT areessential to developing these increasingly marginal fields, and an above-average discount rate is justified to balance the additional risk these project developers inevitably take on.

BOEM recommends that BSEE allow companies to self-report discount rates, but that BSEE impose an upper bound on reported discount rates. BOEM recommends setting this upper discount rate bound at 20 percent for deepwater subsea tiebacks that require EFAT. This discount rate bound is generally consistent with data from the SPEE and the Texas Comptroller of Public Accounts. This 20 percent discount rate bound is greater than the upper bound for the rest of the deepwater (15 percent) but less than the upper bound for shallow water (25 percent). BOEM believes this is appropriate since deepwater subsea tiebacks that require EFAT typically warrant a somewhat higher rate of return than a standard deepwater project to induce development of a marginal resource with additional technological complexities. However, the risk characteristics of these projects are distinct from those associated with shallow water, and the nature and structure of companies operating in deepwater are such that subsea tiebacks that require EFAT do not require a discount rate as high as shallow water projects. This assessment takes into account typical reservoir sizes, development costs, activity trends, typical company characteristics, and macroeconomic trends. This increase in the upper discount rate bound from 15 percent to 20 percent for deepwater subsea tiebacks that require EFAT should lessen the likelihood of stranding resources, allow companies to earn appropriate rates of return, and allow the federal government to receive appropriate royalty payments.

Section 5.2: Practical Considerations

Defining a subsea tieback that requires EFAT (and thus, identifying the projects that are eligible for a higher discount rate) is a complex issue. In general, BOEM defers to BSEE to develop the appropriate definition. BSEE has provided BOEM with preliminary guidance regarding how it will define these projects. BSEE's definition will center around the enhanced flow assurance technology required and will include conditions regarding what makes projects eligible that will be evaluated when reviewing SCRR applications. BSEE's evaluation of an application for EFAT will consider the complexities involved and ensure that they meet these definitions and conditions as approximations of the risk factors that warrant a higher discount rate.

The technologies referenced in Chapter 2 may or may not be considered by BSEE as proven for use in the United States and operators should defer to BSEE guidance that specifically outlines the acceptable technologies, strategies, and cost requirements necessary for a project to qualify.[14] Therefore, BSEE should monitor operator behavior to see how well their definitions target the intended projects and limit unintended consequences. BSEE should also verify that the enhanced flow assurance technology expenditures outlined in an operator's plan are consistent with the expenditures the operator ultimately makes. In addition, this policy should not reverse the general behavior of companies to target the more profitable remaining resources first, followed by the marginal resources. These considerations lend support to not creating too large of a difference between the general deepwater discount rate and the discount rate for deepwater subsea tiebacks that require EFAT. These considerations also provide support to moving gradually with policy changes to observe operator behavior. BOEM has determined that increasing the upper bound discount rate for subsea tiebacks that require EFAT from 15 percent to 20 percent is consistent with these considerations.

Chapter 6: Conclusions

BOEM has examined the available research and data regarding the appropriate discount rates to use in the context of royalty relief applications for deepwater subsea tiebacks that require EFAT. When determining its policy recommendations, BOEM accounted for the numerous factors that determine discount rates, and the fact that these projects likely entail somewhat above-average risks. BOEM recommends that BSEE allow companies to self-report discount rates, but that BSEE impose an upper bound on reported discount rates of 20 percent for deepwater subsea tiebacks requiring EFAT. This 20 percent upper bound would allow companies to earn appropriate rates of return, help ensure deep water resources are not stranded, and protect the government's right to receive appropriate royalty payments.

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[14] BSEE has provided the following preliminary scope of an enhanced subsea tieback project. Technologies like subsea booster pumps which are proven for use in the Gulf, but involve significant scope of supply (specialized and fully qualified offshore equipment designed to operate long-term) in order to enable subsea tieback production that would otherwise not be feasible, may be eligible. These types of technology, which require specialized design, fabrication, and installation for equipment and configurations both subsea and topsides, (including large-footprint subsea structures requiring engineered foundations, dedicated power generation subsea, and additional control- or power-related components in order to successfully use) are available, but not overly common flow assurance technologies.

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Appendix A

BSEE's analysis of recent production rates on existing deepwater GOM facilities revealed that a majority of the facilities were utilizing less than 50 percent of their average daily production capacity. Tables 1 and 2 show the count of deepwater GOM facilities categorized by average utilization, which is calculated as average daily production rates over a 3-year period (2016-2019) divided by the nameplate capacity of each deepwater facility stated as a percentage.

Table 1

GOM Deepwater Facilities by Average Utilization by Oil Production	
Count of Facilities	Percentage Utilization
7	>65% Utilization
8	50-65% Utilization
15	25-49% Utilization
14	10-24% Utilization
24	<10% Utilization

Source: BSEE

Table 2

GOM Deepwater Facilities by Average Utilization by Gas Production	
Count of Facilities	Percentage Utilization
3	>65% Utilization
6	50-65% Utilization
18	25-49% Utilization
14	10-24% Utilization
27	<10% Utilization

Source: BSEE