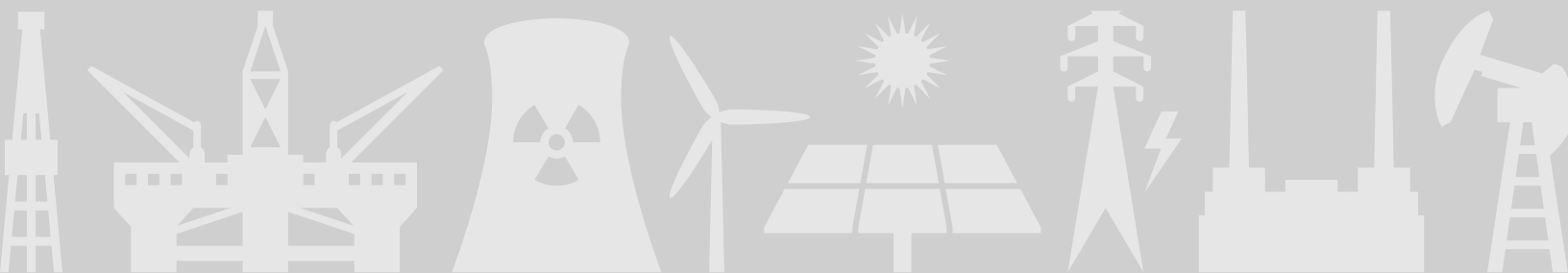


FINANCING SOLAR AND WIND POWER: INSIGHTS FROM OIL AND GAS

by Travis Bradford, Peter Davidson,
Lawrence Rodman and David Sandalow

MARCH 2017



ABOUT THE CENTER ON GLOBAL ENERGY POLICY

The Center on Global Energy Policy provides independent, balanced, data-driven analysis to help policymakers navigate the complex world of energy. We approach energy as an economic, security, and environmental concern. And we draw on the resources of a world-class institution, faculty with real-world experience, and a location in the world's finance and media capital. Visit us at energypolicy.columbia.edu

 facebook.com/ColumbiaUEnergy



twitter.com/ColumbiaUEnergy

ABOUT THE SCHOOL OF INTERNATIONAL AND PUBLIC AFFAIRS

SIPA's mission is to empower people to serve the global public interest. Our goal is to foster economic growth, sustainable development, social progress, and democratic governance by educating public policy professionals, producing policy-related research, and conveying the results to the world. Based in New York City, with a student body that is 50 percent international and educational partners in cities around the world, SIPA is the most global of public policy schools. For more information, please visit www.sipa.columbia.edu





FINANCING SOLAR AND WIND POWER: INSIGHTS FROM OIL AND GAS

by Travis Bradford, Peter Davidson, Lawrence Rodman
and David Sandalow

MARCH 2017

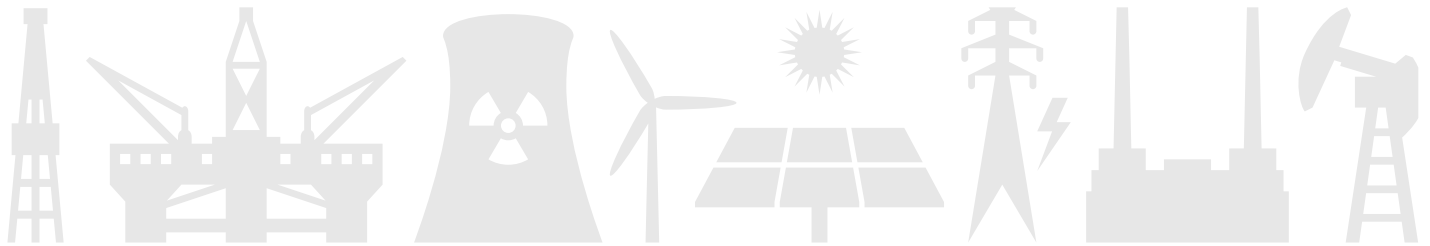
Travis Bradford is a Professor of Professional Practice at Columbia University's School of International and Public Affairs, co-teaching at Columbia Business School, Columbia School of Engineering and the Earth Institute. He also serves as President of the Prometheus Institute, where he advises companies on energy and resource technology strategy.

Peter Davidson is CEO of Aligned Intermediary, an investment advisory group. He has served in senior positions at the US Department of Energy, New York State's economic development agency (ESDC) and the Port Authority of New York and New Jersey.

Lawrence Rodman is a Principal at Aligned Intermediary, as well as a Lecturer at the Yale School of Forestry and Environmental Studies. He spent a previous career practicing law, primarily in corporate finance, in New York City.

David Sandalow is the Inaugural Fellow at the Center on Global Energy Policy, School of International and Public Affairs, Columbia University. He has served in senior positions at the White House, State Department and US Department of Energy.

COLUMBIA UNIVERSITY IN THE CITY OF NEW YORK



ACKNOWLEDGMENTS

The authors are deeply grateful to those who spent time discussing the ideas in this paper and reviewing drafts, including Jason Bordoff, Jonathan Chanis, Bruce Chung, Ken Gillingham, Daniel Gross, Jim Guidera, Antoine Half, Joel Moser, Brooks Klimley, Martin McAspurn-Lohmann, John MacWilliams, Jesse Pichel, Curtis Probst and three anonymous reviewers. We extend special thanks to Lauren Cope, Nan Lin, Samriddhi Malla, Thomas Rollason, Namiko Sawaki and Joel Smith, who researched these issues as part of a graduate student project at the School of International and Public Affairs at Columbia University in winter and spring 2016.

TABLE OF CONTENTS

Executive Summary	4
I. Solar and Wind Finance	5
A. Social Benefits of Solar and Wind Power	5
B. Scale of the Investment Need	5
C. Sources of Capital for Solar and Wind Power	6
II. Oil and Gas Finance	7
A. Current Scale	7
B. Comparing Oil and Gas Assets to Solar and Wind Assets	8
III. Learning from Oil and Gas	9
A. Steps to Date	9
B. Three Proposals	10
1. Renewable Resource Based Finance	10
2. Electricity Production Payments	15
3. Capacity Payment Finance	18
C. Next Steps	20
IV. Conclusion	21
Notes	22

EXECUTIVE SUMMARY

The solar and wind power industries must raise trillions of dollars in the decades ahead to achieve the scale of older, more established energy sources. While investment in solar and wind power has grown in recent years, reaching a record \$270 billion in 2015, such investment declined by roughly 16% to \$226 billion in 2016.¹ Solar and wind developers often struggle to obtain adequate financing on competitive terms.

The global oil and gas industry has a long and deep track record of financing its capital needs. At the top of the most recent commodity price cycle in 2013, the oil and gas industry was investing roughly \$900 billion annually.²

In this paper we consider whether the successes of the oil and gas industry in raising capital could provide insights to help the solar and wind power industries expand. There are, of course, important differences between oil and gas assets on the one hand and solar and wind power assets on the other. One of these is the potential for upstream oil and gas assets to generate extraordinary cash flows relative to capital invested. (Indeed the phrase “striking oil” is often used as a metaphor outside the oil and gas industry to describe situations with especially lucrative returns.) There are also similarities, including the role of technologies, need for development capital and exposure to business cycles. Examining the finance tools of the oil and gas industry could help suggest strategies for the solar and wind power industries to access additional and cheaper capital.

This would deliver important social benefits. Solar and wind power create neither local air pollutants nor greenhouse gases. Solar power and community-scale wind turbines can deliver electricity in remote locations without access to a power grid, providing electricity to those who now lack it. Partly for these reasons, governments around the world strongly support the development of solar and wind power.

A substantial body of literature has examined the scale of investment in solar and wind power needed to achieve climate change mitigation goals in particular. This literature suggests that to meet the agreed international target of limiting global warming to 2°C/3.6°F above pre-industrial temperatures, the investment need in solar and wind power facilities alone is roughly \$500 billion per year over the next twenty-five years.³ This is almost double the current rate of investment in solar and wind facilities.

This report offers an initial analysis of the potential for oil and gas finance tools to serve as models for solar and wind power projects. Based on our analysis, we propose three new tools:

- **Renewable resource based finance.** For decades, the upstream oil and gas sector has used reserve-based finance for exploration and production (E&P), with oil and gas reserves providing the asset base and security for a loan. Similarly, solar and wind resources at a project site could provide an asset base and security to support debt financing, if those resources were sufficiently valuable. This would be particularly useful at the pre-construction development phase of a solar or wind project, where capital constraints are often significant.
- **Electricity production payments.** The volumetric production payment (VPP) is another tool that oil and gas companies use to finance E&P. In VPP financing, a capital provider makes a current payment to an E&P company in exchange for the right to receive oil or gas, or proceeds from the sale of oil or gas, in the future. A similar tool could help finance solar and wind power projects, with capital providers making a current payment in exchange for the right to receive proceeds from the future sale of solar or wind power at a site. This capital could help finance the project development stage and serve as a supplement or alternative to project finance for the long term.

- **Capacity payment finance.** In the oil and gas industry, facilities such as natural gas pipelines often produce two separate payment streams—one based on the amount of the gas transported and the other based on the right to use the asset. Generators of electricity have two analogous payment streams—traditional energy payments based on the amount of electricity delivered and capacity payments provided for keeping electric generation capacity available and ready for use. Capacity payments are of increasing importance in some wholesale electricity markets and can, to some degree, be available for solar and wind power facilities. These capacity payments provide separable revenue streams that may have the potential to help improve access to capital and lower capital costs for some projects.

Further work is needed for these proposals to be market-ready. We offer the proposals in the hope of spurring dialogue about their potential and stimulating “outside the box” thinking about financing solar and wind power assets. We hope that financiers, developers and policymakers will pursue these and other new ideas to help address the significant unsatisfied need for capital flows into solar and wind power infrastructure.

I. Solar and Wind Finance

A. Social Benefits of Solar and Wind Power

Solar and wind power have important social benefits. These technologies produce almost no local air pollution or greenhouse gas emissions. In the United States, competing types of electricity generation cause health impacts including asthma, heart attacks and cancer, estimated to cost between \$362 billion and \$686 billion annually.⁴ Figures in parts of Asia are much higher.

In addition, solar photovoltaic power uses minimal water and wind power uses no water. Other leading types of electricity generation use large amounts of water, both in fuel extraction and cooling.⁵ This is especially important in parts of the world with poor water resources but good solar and wind resources.

Approximately 1.2 billion people, or 16 percent of the world population, did not have access to electricity in 2016.⁶ Many of these people live in remote rural areas, far from an electric transmission grid. Solar PV and small-scale wind can help alleviate energy poverty in these remote areas by producing electricity for local use without a grid connection. Additional benefits include increased resilience of communities, reduced security risk and reduced exposure to volatile fuel prices.⁷



Finally, solar and wind power generation provide electricity with almost no life-cycle greenhouse gas emissions.⁸ Solar and wind power will play an important role in achieving the goal of limiting global warming to 2°C/3.6°F above pre-industrial temperatures, adopted by 195 countries at COP 21 in Paris.

B. Scale of the Investment Need

Meeting this climate challenge in the next few decades will require unprecedented changes in the capital asset base of the global energy industry.⁹ The International Energy Agency (IEA) estimates that to meet a 2°C/3.6°F target, the world will need to invest \$40 trillion in clean energy research, development, demonstration and deployment (RDD&D) (including power generation, transport, industry and buildings) through 2050, over and above what it would invest in all energy RDD&D under business as usual (BAU).¹⁰ This clean energy investment need—an average of more than an additional \$1 trillion annually—dwarfs the actual 2015 investment in clean energy of \$329 billion.¹¹

Within the broader clean energy investment need that the IEA describes in its report, the clean electric power generation subsector alone accounts for a substantial part of that overall need. Bloomberg New Energy Finance (BNEF) and Ceres forecast that \$12.1 trillion of investment is required in “new renewable” power (which includes solar, wind, geothermal and biomass/waste-to-energy) over the next 25 years if the world is to have a chance of meeting the 2°C/3.6°F goal.¹² BNEF and Ceres project BAU investment in new renewable power of \$6.9 trillion during this period.¹³ This makes a cumulative investment gap in these renewable power assets of more than \$5 trillion.

Solar and wind power have the potential to play a central role in helping meet climate mitigation goals. Ensuring that these technologies have access to global capital markets at the right price will be critical as these industries grow.

C. Sources of Capital for Solar and Wind Power

From very modest beginnings in the 1970s and 1980s, investment in solar and wind power has grown substantially in recent years, reaching a peak of \$270 billion in 2015.¹⁴ Early investment came mostly from government research and development budgets. As costs declined, private capital began to enter the sector, although often at a high price.

Historically, equity investment in solar and wind projects came largely from developer equity. In the middle of the last decade, venture capital firms began investing in solar and wind technology companies, but this had limited impact on equity for project development. In general, those technology company investments performed poorly, leading many venture capitalists and other equity investors to shun both the clean tech and clean power deployment sectors in recent years.

Solar developers also began using securitization as a long-term finance tool for solar assets, particularly for leases of residential and commercial/industrial rooftop systems. In a securitization, the owner of a pool of standardized financial assets, such as solar loans or leases, transfers title to an entity formed for the purpose. That entity in turn issues its own securities based on the cash flows from, and secured by, the pooled assets. While an effective tool for large pools of small, similar loans or leases, this type of finance is much less useful for larger and more bespoke utility-scale projects.

In the middle of the last decade, some European banks began providing debt capital for solar and wind projects. However, credit for such projects froze almost completely with the financial crisis of 2008. For the next several years, debt capital was almost completely unavailable for solar and wind development. Even utility-scale solar and wind projects with long-term power purchase agreements (PPAs) were unable to obtain long-term debt financing. As a

result, the US Department of Energy's Loan Guarantee Program stepped in to guarantee debt for a half dozen such projects. Commercial banks and other lenders followed once the viability of such projects had been demonstrated.

Today, ample debt capital is available for utility-scale solar and wind projects with long-term PPAs. A small share of equity financing for solar and wind projects in recent years has come from yieldcos and other public market vehicles (discussed in more detail below). However, raising equity to finance the preconstruction development stage of such projects is often a significant challenge.

Institutional investors have been largely missing from the mix, both in equity and debt. (By "institutional investors," we mean pension funds, endowments, insurance companies, sovereign wealth funds and foundations. We do not include commercial and investment banks.) Institutional investors manage vast amounts of capital: the OECD and Climate Policy Initiative estimated assets under management at \$79 trillion in 2010.¹⁵ But to date these investors have supplied only a small portion of the debt and a negligible amount of equity for renewable energy.¹⁶ Their allocations to renewable energy are tiny. Pension funds, for example, have allocated just 0.1 percent of their total assets to renewable energy infrastructure. Pension funds and insurance companies accounted for less than 2.5 percent of all clean energy asset finance between 2004 and 2011.¹⁷

To meet their capital needs, the solar and wind power industries would benefit from finding ways to tap into the deep financial resources of institutional investors. To do this, these industries need to develop a broader array of financing tools that respond to the risk/return requirements of institutional investors.

II. Oil and Gas Finance

A. Current Scale

The oil and gas industry raises enormous amounts of capital each year. In 2013, at the top of the most recent commodity price cycle, the oil and gas industry invested roughly \$900 billion in fossil fuel supply. Of this amount, almost \$700 billion was in the upstream sector, roughly \$150 billion was in the midstream (oil and gas pipelines and shipping, and LNG) and the balance was in oil refining in the downstream sector.¹⁸ This total investment is more than double the level (in real terms) in 2000¹⁹. Although investment in the upstream sector dropped to under \$600 billion as oil prices fell sharply and the industry experienced a wave of bankruptcies in 2015,²⁰ the scale of these numbers and their growth since 2000 demonstrate that capital markets have the capacity to supply investment at the level needed for clean power.



A wide range of financing tools and sources of capital support investment in the oil and gas industry. In the upstream sector, independent exploration and production companies obtain reserve based financing from banks based on proved (and in some markets, probable) reserves.²¹ These companies obtain additional financing from investors through a variety of unique tools including volumetric production payments, farmout agreements, net profit interest and mezzanine debt with equity features.²²

Major oil and gas companies with large cash flows and, in the case of national oil companies, the backing of national treasuries, finance exploration and development from their balance sheets. In the midstream sector in the United States, pipeline companies finance oil and gas pipelines through tax-advantaged master limited partnership and real estate investment trust structures that source their capital in the public equity capital markets. Pipelines and other large-scale midstream and downstream assets, such as LNG facilities, refineries and tankers, are also financed through project financing in which banks and some institutional investors are participants.

B. Comparing Oil and Gas Assets to Solar and Wind Assets

The oil and gas industry consists of three sectors: upstream, which includes exploration, development and production; midstream, which includes pipelines, gas liquefaction plants, tankers and other transportation-related assets; and downstream, which includes refineries and other processing facilities and marketing assets. As such, oil and gas is a more diverse industry than solar and wind power generation. Yet there are important similarities between the two industries:

- Both have continually evolving technology and know-how directed toward reducing cost and more efficiently exploiting an energy resource.
- Both require significant development capital for activities at a project before revenue is generated.
- Both require long-term capital for projects.
- Both are subject to price volatility.
- Both are regulated and subsidized by widely varying laws and regulations around the world.

While these similarities suggest parallels in the financing tools that can serve each industry, there are differences that make financing, particularly at the development stage, easier to accomplish for the oil and gas industry than for the wind and solar generation industry.

First, the oil and gas industry has many companies with substantial balance sheets. That gives these companies the ability to fund capital investments internally. These companies operate in geographically diverse markets and, in the case of vertically integrated companies, offer a wide range of products that enable them to diversify risk internally. These large companies have extensive experience evaluating risk, which allows them to make rational bets on exploration. It may be that this experience and ability to evaluate risk led to oil and gas industry growth, or that the large scale of companies in the industry positions them to take risk, or both. Either way, the oil and gas industry is able to fund exploration and development projects despite high risks, including those related to drilling in the Arctic or deepwater offshore or those related to working in a politically unstable country. While some large solar and wind power developers have begun to emerge in recent years, none have financing capacity at the scale of the major oil and gas companies. Solar and wind developers do not have the balance sheet capacity to take on large-scale projects around the world. Consequently, solar and wind remain challenged by the reluctance of external capital providers to take project development risk.

Second, oil and gas products typically can be sold into much larger markets than electricity from solar and wind power projects. Regardless of where oil is discovered and produced, the market for that oil is global. A company that produces oil is not dependent on demand from local markets, nor is it required to take the risks of selling that oil in the local markets, which may include country risk. Natural gas markets are mostly regional, with a growing global market for LNG. By contrast, electricity must be sold and used either where it is produced, or if the generating facility is connected to a grid, within the market served by that grid. This is a restriction that impacts solar and wind generation more than coal- or gas-fired generation. Solar and wind can be sited only where those resources exist, whereas a coal or gas plant can be located at a more optimal location in relation to the grid and close to the load it serves because its energy source is portable.

Third, the industries differ in the range of returns they offer. Long-term financing of solar and wind power typically offers steady bond-like returns. The business of developing renewable power generation is more risky and offers higher, equity returns. There are parallels in the oil and gas industry, in which pipelines with stable long-term cash flows offer bond-like returns while some riskier midstream and downstream assets offer equity returns. Yet the upstream exploration and production sector offers the potential of extraordinary, outsized equity returns. (Indeed “striking oil” is a metaphor for hitting it big with an investment in any sector.) This strike-it-rich potential is not available in solar and wind power generation.

There are several potential strategies for addressing these development stage capital problems in the solar and wind industries:

- First, the solar and wind industries may need to grow well-capitalized companies with balance sheet financing capacity at the scale of the international and national oil companies. As a variation on this approach, utility companies and current energy majors could bring their balance sheets to bear as major developers of solar and wind capacity. This has started to happen in the United States, with several large utilities including NextEra and Southern Company developing renewable energy projects.
- Second, taking a page from the oil and gas playbook, several project developers could form project joint ventures to spread the risk of individual projects. Having multiple parties that have the ability to complete the project would reduce the completion risk as perceived by capital sources.
- Third, completion guarantees could be a tool to help reduce development stage risk for potential capital sources.
- Finally, the solar and wind industries could adopt new financing tools modeled in whole or in part on those successfully used by the oil and gas industry for many years. We suggest three such financing tools below.

III. Learning from Oil and Gas

The oil and gas industry has been hugely successful at mobilizing cheap capital. Can the solar and wind industries learn from that success, particularly for pre-construction development for which financing remains expensive and often difficult to obtain? Considerable commentary has focused on one financing tool that the oil and gas industry uses—the master limited partnership (MLP)—and the potential benefits of using that tool for solar and wind projects. We believe the solar and wind industries could benefit from considering other possible financing tools based on the experience of the oil and gas industry. We propose three in Section B below.

A. Steps to Date

US law gives oil and gas companies the right to form master limited partnerships to own certain assets, which are not subject to income taxation at the entity level. The oil and gas industry relies heavily on MLPs (for financing pipelines in

particular), in substantial part because of the important tax advantages MLPs provide.²³ Solar and wind developers have noted the MLP structure with interest, seeing MLPs as a potentially attractive tool for raising capital. However, under current law, solar and wind projects are not eligible to establish master limited partnerships. This has led to extensive commentary arguing solar and wind projects should be entitled to the same MLP tax benefits as oil and gas projects,²⁴ as well as legislation to extend eligibility for MLP treatment to solar and wind.²⁵ That legislation has stalled in Congress due to partisan polarization on energy issues and resistance from some economists and policymakers who argue that eliminating MLPs entirely, instead of extending MLPs to solar and wind projects, would better level the playing field.

In part because MLP treatment is not available for solar and wind projects, the financial markets created an alternative known as “yieldcos” (also sometimes called “synthetic MLPs”). Like MLPs, yieldcos are designed to provide investors with stable cash flows at low risk. Yieldcos cannot offer the tax benefits of MLPs, but they can shelter some investor income with net operating losses, accelerated depreciation and other tools. Like MLPs, yieldcos have a growth component and a current yield component. The yieldco model initially targeted total returns (current yield plus growth) in the 15 percent range, considerably higher than MLPs. This mixing of stable cash flows and growth, coupled with a diverse pool of assets, often made yieldcos difficult for investors to evaluate, and prices have fluctuated significantly. The bankruptcies of Sun Edison and Abengoa led to significant declines in yieldco values. While the yieldco markets have substantially recovered, and ultimately may be a successful source of long-term capital, an extension of the MLP structure to cover renewables would be more effective than yieldcos in putting renewables on a more even footing with oil and gas.

Price hedging has been used in the oil and gas industry, as well as many other commodity businesses, for decades. Renewable power markets have begun to use hedging as well, starting in Texas where hedging in the wind market began in 2013–2014 as an alternative to PPAs.²⁶ In this type of transaction, a wind generator buys a hedge from a financial counterparty covering a part of its production, with a term of up to 13 years. The hedge locks the price that the generator receives for its electricity into a specified range. As such, the hedge functions not just as a way to mitigate risk of volatile electricity prices but as an electricity offtaker and the basis for other financing in a manner similar to PPAs. A variation on the financial hedge, the synthetic PPA, has also developed in recent years. A corporate user purchases the economic ownership of the electricity under a long-term fixed-price contract. The user then purchases the electricity it needs in the wholesale market, the generator sells the electricity it produces in that market, and the corporate user either benefits or loses on the price differential from the synthetic PPA price. These tools only recently have begun to penetrate the market and have potential for much broader use in the future.²⁷

The experience to date suggests the potential for other financial tools used in the oil and gas industry to help mobilize capital for solar and wind projects.

B. Three Proposals

Below we suggest three new tools for financing solar and wind projects, drawn from the oil and gas experience. We hope consideration of these potential financing tools may lead to development of others as well.

1. Renewable Resource Based Finance

In reserve based finance (RBF) for oil and gas producers, oil and gas reserves provide the asset base and security for a loan. The upstream oil and gas sector has used RBF to finance exploration and development for decades. Could a similar tool finance solar and wind project development, relying on solar and wind resources, at a cost of capital that may be in line with bank financing and cheaper than equity? This section summarizes RBF in the oil and gas industry and proposes a new tool—“renewable resource based finance” or “RRBF.”

Current—Reserve Based Finance in Oil and Gas

In RBF, one or more lenders, typically commercial banks, lend to an exploration and production (E&P) company against the collateral of oil and gas reserves, and look primarily to the cash flows from production and sale of oil and gas for repayment of the loan. There are two models of RBF: one used largely in the United States and Canada (the North American model), and the other used throughout much of the rest of the world (the international model).

North American RBF is on-balance sheet bank financing for independent E&P companies. The lender makes advances under a revolving credit agreement, based on a borrowing base that is determined by proved reserves.^{28,29} The borrowing base is the present value of qualifying proved reserves, which includes a high percentage of those reserves that are already developed and producing, and lesser percentages of those reserves that are either undeveloped or developed but not yet producing. Advance rates, typically in the 55–60 percent range, further restrict the amount of the funds the borrower may draw against the borrowing base. Loan facilities usually have a three- to five-year term, are non-amortizing and come due in a bullet payment at maturity. Loans are the recourse obligation of the borrower and are secured by a mortgage on reserves in the ground and by UCC security interest in produced oil and gas and proceeds.³⁰ While the sizing of RBF loans is based on proved reserve assets, borrowers may use loan proceeds to finance operations generally, not just production activities.³¹

The international model of RBF has its origins in single-field project finance for North Sea exploration and development by E&P companies. As the model evolved, E&P companies combined cash flows from portfolios of producing properties with expected cash flows from new development projects to produce greater debt capacity for exploration and development. Loan facilities may be in the form of a term loan or a revolving credit facility, with a borrowing base limiting the amount of loans under the facility that may be outstanding. In contrast to the North American model, the borrowing base typically includes some value for probable reserves in addition to proved reserves. Consequently, lenders usually require a guarantee or other credit enhancement from a high-credit parent company or other source, until reserves are proved and development of the field is completed. Loan tenors generally are in the range of five to seven years but may be longer in some markets. The loan facility amortizes over its term but in any event must fully amortize by a “reserve tail date,” which is a date at which a specified percentage (often 25 percent) of the original reserves remain in the ground. Security for the loan is limited by the fact that in most countries outside the United States and Canada, reserves are owned by the country, and local law often provides other restrictions on what can serve as collateral.³²

RBF Revenue Stream and Risks. Regular RBF debt service payments are due from the inception of the loan. Since RBF finances development and production, the lender must structure the loan to make sure that there is a source of cash to pay debt service. In the North American market, this source is other properties of the borrower that are already producing oil or gas. In the international market in which RBF can serve as project finance, the lender can take a debt service reserve from loan proceeds as a source of payment until the field starts producing.

RBF lenders face risks and mitigate them as follows:

- Reserve, completion and production risk—In the North American market, lenders face production risk but not material geologic risk because they do not include unproved reserves in the borrowing base. Consequently, the borrower E&P company has access to senior bank credit for new exploration and development only to the extent of the credit value of its proved fields and the cash flow from its producing fields. Therefore, in order to raise additional capital for exploration and development, E&P companies that do not have sufficient retained earnings must turn to other sources that demand higher returns, such as second lien loans or high yield bonds (higher interest rates), mezzanine loans (equity kickers), volumetric production payments (participation in

production) and private equity (participation in equity).³³ In the international market, lenders do take geologic risk because they give value to unproved reserves in the borrowing base. In either market, pooling production with exploration fields in a single facility reduces lender risk, and guarantees and other credit enhancements shift risk to third parties. Lenders also reduce reserve risk by discounting the value of reserves in various ways, including counting only a percentage of the value of reserves in the borrowing base,³⁴ limiting advances to a percentage of the borrowing base³⁵ and using high discount rates in computing present value of reserves.³⁶

- **Commodity price risk**—Lenders are exposed to price risk because they depend on sales of oil and gas at market prices for repayment of loans. Lenders mitigate this risk by using conservative price assumptions and frequently reevaluating reserves and adjusting the loan facility accordingly. Lenders also may require borrowers to hedge commodity prices.
- **Borrower operating and solvency risk**—In the North American market, lenders have low risk because loans are fully secured and advance rates limit the amount of loans outstanding. In the international market, lenders take greater risk because local law in many countries restricts what can serve as collateral security. Lenders in this market therefore tend to more tightly restrict other debt in the capital structure than North American RBF lenders do.³⁷
- **Refinancing risk**—This risk is low for international RBF lenders because loan agreements typically require full amortization well ahead of the expected exhaustion of the producing oil and gas fields. Lenders in the North American market face refinancing risk because loans do not amortize, so they control this risk through conservative underwriting and frequent re-evaluation of reserves.

Proposal—Renewable Resource Based Financing (RRBF)

Every parcel of land receives some amount of sunshine and wind. The solar and wind resources at a site are potential assets, similar in important respects to oil and gas reserves. The similarities suggest consideration of whether reserve based financing in the oil and gas industry could serve as a model for a new financing tool for solar and wind projects, perhaps a “renewable resource based financing” or “RRBF.”



The similarities between oil and gas reserves and solar and wind resources include the following:

- First, sunshine and wind are potential revenue-producing energy sources, like oil and gas reserves.
- Second, the owner of a site is legally entitled to control use of the solar and wind resource at that site, just as the owner of oil and gas reserves is legally entitled (at least in the United States) to control use of those reserves.
- Third, the amount of sunshine and wind at a site is often known within a definable range of uncertainty, similar to estimates of oil and gas reserves.
- Fourth, as with oil and gas reserves, the right to use and develop solar or wind resources can be embodied in a contract, which can serve as the basis for a security interest (potentially in the form of a real estate mortgage).

There are differences, of course. Oil and gas are tangible physical products, with well-recognized value. Sunshine and wind are not. A central issue in the viability of RRBF as a financing tool, in fact, is whether the solar or wind resource has sufficient value to support financing. Many sites have sufficient solar radiation to support a solar photovoltaic facility, for example. Scarcity of usable solar and wind resources is necessary to give them substantial value. Some part of that scarcity arises from community, political, environmental and similar barriers to development that take many potential sites out of the market. Scarcity will also arise over time as many of the best and most accessible sites become developed. Keeping these limitations in mind, we explore below some of the issues in structuring a RRBF facility.

Sample Financing Structure. Consider the following possible financing structure. The developer of a new wind farm signs a long-term contract with a landowner for the right to develop and use the wind resource on a parcel of land. If that parcel is sufficiently unique, so the wind resource is an asset with value, a bank could lend against that value—an RRBF loan—subject to appropriate discounts for uncertainties such as completion risk, interconnection, pricing, etc. The developer could use the loan proceeds to fund the costs of development, a project stage that is often capital constrained. These development costs include purchasing the resource and development rights from the landowner, engineering, permitting, environmental impact statement, etc. If the project does not go forward, the bank could recover its loan by selling the wind resource asset to another developer.

The contract between the landowner and the developer could take the form of a purchase with a one-time payment funded by the RRBF. Alternatively, the developer could lease the wind resource rights from the landowner so that the landowner in effect finances part of the project costs. The developer could still borrow from a bank under the RRBF model, using the rights under the lease of the wind resource as collateral (similar to real estate leasehold financing), and then use the loan proceeds to fund other development costs.

A barrier to this RRBF model at the development stage is that there is no source of cash flow to pay debt service on the loan. One approach to this problem is to depart from the oil and gas model and not require debt service payments until the developer closes on construction finance for the project. This structure increases the risk to the RRBF lender. An alternative is to use part of the loan proceeds to fund a debt service reserve.

Risk Allocation. RRBF lenders would face the following risks:

- Resource risk—This is the risk of how much electricity the wind or solar resource can actually produce and at what times of day (when in the load demand curve) that resource is available. (RRBF lenders for oil and gas face similar risks with respect to the size of reserves.) While it may be possible to predict with high accuracy the

average amount of sun or wind at a site, day-to-day variability introduces uncertainty that reduces the reliability of a site's generation. Lenders can mitigate that risk by applying discounts to the projected amount of the solar or wind resource, similar to the discounts that RBF lenders apply to oil and gas reserves.

- **Completion/refinancing risk**—In the development stage model described above, RRBF provides finance until the developer can close on project finance for the construction and long-term operation of the generation facility. The developer will not be able to obtain project finance unless it signs a PPA or other type of offtake agreement that gives the project finance lenders assurance of a steady cash flow stream for the life of the project loan. So a solar or wind RRBF lender takes the risk of the developer signing such an agreement. While this bears some similarity to the risk that RBF lenders in the international market take on in obtaining takeout financing by project finance, there is not the same risk arising from a need for an offtake agreement because oil (and to some extent gas) are global commodity markets.
- **Commodity price risk**—The RRBF lender in a development stage model takes this risk only indirectly, as it may affect the likelihood that the developer closes on takeout financing that will pay off the RRBF loan.
- **Operating and solvency risk**—The RRBF lender at the development stage will take the risk of the developer's capabilities as a developer. If the developer is not successful in completing the project, the lender will need to exercise its collateral rights and potentially sell the solar or wind resource in order to recover its loan. This resource is less tangible than oil or gas reserves in the ground, and lenders may view this difference as making the solar or wind resource riskier as collateral than oil or gas. However, oil and gas in the ground is in some respects just as intangible as the solar or wind resource. Each is a source of energy that can be sold in the future, but only after it is produced. In fact, the asset that an RBF lender for oil and gas effectively forecloses is the bundle of rights to produce and sell the reserves, which is also an intangible. RBF lenders use reserve reports, prepared by independent petroleum engineers, as a key input in underwriting RBF loans. This reserve report process is deeply ingrained in RBF. A similar process for wind and solar, in which banks develop a relationship of trust with independent engineers who can appraise the value of the solar or wind resource, may help lenders to get comfortable that the collateral is marketable and has sufficient value to fully secure the RRBF loan.
- **Credit risk**—RBF is a recourse form of financing. In the North American market, the loan is made to the E&P company with full recourse. In the international market, at least until properties are producing, the loan requires credit support from a parent company of the development company or other credit party. In RRBF, even if the solar or wind resource collateral has sufficient value to substantially or fully secure the RRBF loan, the lender will still look to the credit of the project developer. However, the value of the solar or wind resource as collateral could be enough credit enhancement to make corporate-level debt available to developers that otherwise would not qualify.

RRBF for Long-Term Finance. RRBF could be applicable as well to long-term finance for solar and wind power generation. The owner of the wind or solar resource (either the landowner or someone with contractual rights to the resource) would lease the resource to a completed project for its useful life. A bank could then make a loan to the owner of the resource, against the security of the resource asset and the cash flow from the lease payments that the resource owner receives from the project. In some respects, this model may be a closer parallel to RBF for oil and gas than the development stage finance model. The lender uses the resource (that is, oil in the ground, or the solar or wind resource) as collateral security, but the loan is based on cash flow from an operating project. However, RBF is short- to mid-term financing—three- to five-year terms in the North American market, and up to seven years in the international market. This would be a barrier to thinking about applying RBF as long-term RRBF finance for solar and wind.

In a variation on this model, instead of leasing the wind or solar resource to the project owner, the resource owner might provide the resource to the generation facility under a toll conversion model. The resource owner would pay the project owner a toll conversion fee to “convert” the solar radiation or wind to electricity. The resource owner would own, and be entitled to sell, the electricity produced. If the toll conversion agreement is structured as a take-or-pay contract, so that the resource owner must pay the project owner whether or not it submits resource for conversion to electricity, and if the resource owner has sufficiently high credit, this contractual arrangement might serve as an alternative to a classic PPA and form the basis for project finance for the project. This structure would separate the resource and commodity price risks from the relatively lower technology and operating risks of the generation facility.

As we note above, a gating issue for viability of RRBF is whether the market will attribute sufficient “value” to the solar or wind resource. That will depend in part on whether a site has a unique wind or solar resource or a cost advantage over other sites, as well as supply and demand for renewable power generation, among other factors.

2. Electricity Production Payments

The volumetric production payment (VPP) is part of the arsenal of tools that oil and gas exploration and production (E&P) companies use to finance exploration and development. A structure similar to VPPs offers potential as a financing tool for solar and wind power generation, both as funding during the project development stage and as a supplement, or even an alternative, to project finance for the long term. This section summarizes VPPs in the oil and gas industry and proposes a new tool—an “electricity production payment” or “EPP.”

Current—Volumetric Production Payments in Oil and Gas

In a VPP, a provider of capital makes a current payment to an E&P company to purchase the right to receive in the future either produced oil or gas (a production-denominated VPP), or money (a dollar-denominated VPP). The E&P company is in effect forward selling an asset.

In a production-denominated VPP, the buyer of the VPP (the capital provider) purchases a contractual right to receive a percentage or volume of monthly (or other period) production from an oil or gas property. The VPP rights may expire after a period of months or years, or after the buyer receives a specified total volume of oil or gas. The contract may provide that if there is a shortfall in any period, the E&P company must make up that shortfall in later periods. The buyer may market the production it receives, or it may contract with the E&P company to market that production on its behalf. Under the alternative dollar-denominated VPP, the buyer purchases the right to receive a specified dollar amount per monthly (or other) period, instead of a share of actual production. Similar to the production-denominated structure, the contract may provide that the producer must make up shortfalls from sales in a later period. Under either type of VPP, the E&P company owns the oil or gas until it is produced and retains the rights and responsibilities of exploration, development and production.

VPP Revenue Stream and Risks. E&P companies use VPPs to monetize a portion of the oil and gas production stream before the hydrocarbons are actually extracted and sold. Until a field starts producing hydrocarbons, there is no revenue stream available to the VPP buyer. So the earlier in the field development process that the VPP buyer purchases its interest, the greater risk it takes. Some of the risks that VPP buyers take and how they mitigate those risks are:

- Reserve, completion and production risk—Because the buyer acquires an interest in reserves in the ground, potentially it takes all of these risks. The buyer can mitigate risk by (i) limiting the investment in VPPs to proved reserves and to fields that have completed, producing wells, (ii) performing due diligence and procuring independent reserve reports, (iii) having the VPP cover a diversified set of properties, and (iv) sizing and

structuring the VPP so that a shortfall in production in any period is borne first by the producer, and there is room to make up a shortfall in one period from production in subsequent periods.³⁸

- **Commodity price risk**—In a production-denominated VPP, the buyer assumes commodity price risk, which it can mitigate by hedging commodity prices. The buyer of a dollar-denominated VPP does not assume this risk.
- **Operating risk**—The buyer takes the risk of the VPP seller’s operations and efficiency of production, but does not have any control over operations. The buyer can mitigate this risk by limiting the share of production that is subject to the VPP so that oil or gas production achieves the volume or dollar target even if operations are not efficient.
- **VPP seller solvency risk**—For a volume-denominated VPP, in states where the VPP is considered real estate under state law and not part of the seller bankruptcy estate, the buyer would not take solvency risk. For a volume-denominated VPP in a state where this is not the case, and for a dollar-denominated VPP, which is a payment right, not real estate, the buyer of the VPP takes solvency risk. The buyer can limit solvency risk by requiring that the asset be held in a bankruptcy remote entity, as well as by taking a UCC security interest in the future payment stream, but this may be difficult to structure and be subject to senior liens.

This risk analysis highlights some key features of VPPs:

- The two alternative structures—volume-denominated VPP or dollar-denominated VPP—permit the VPP buyer and seller to choose who bears the commodity price risk.
- The size of the VPP, as a share of total expected production together with the priority and other terms of the shortfall makeup provisions, also allow the buyer and seller to tailor the allocation of risk between them.
- The parties can price the VPP to produce an expected return that reflects the risks that the buyer takes.

Benefits to the VPP Seller. An E&P company that owns oil or gas reserves can monetize a part of the value of those reserves and use the proceeds to invest in new properties, pay down debt, finance capital expenditures or fund operating expenses. The VPP allows the seller to lay off some of the risk of individual properties and diversify its exploration and production risk over a larger range of properties. Because payment under a VPP is due only from actual production, the VPP is not a debt obligation, so it does not increase the seller’s risk from leverage and does not require guarantees or other credit enhancement. While the seller gives up some of the potential upside of a property, it does not transfer any entity-level equity to the buyer. Thus, VPPs are a flexible financing tool that can be tailored to the specific property, the needs of the E&P company and the risk/return requirements of the investor.

Proposal—Solar or Wind Electricity Production Payments (EPP)

Development Stage Finance Model. Once a solar or wind developer has tied up a project site and done some initial project planning and engineering, the developer has a potential asset—the future electricity generation at the site. An “electricity production payment” (EPP), similar to volumetric production payments for oil and gas, could offer a finance structure for the developer to monetize that asset. The buyer of the EPP would purchase a right to receive a portion of the future production of electricity, either as a number of kilowatt hours per time period (a kilowatt-denominated EPP) or a dollar value of electricity production (a dollar-denominated EPP). The developer receives cash that it can use to fund development costs of the project. While the developer also might use the cash to fund other projects, pay down debt or fund operating costs, the EPP buyer may want to limit the use of proceeds to project expenses in order to reduce completion risk for the project. Similar to the VPP model in oil and gas, the buyer purchases only a limited equity interest in the project, not equity in the developer. This structure is not dependent

on the credit of the developer; it is essentially nonrecourse financing. This could be particularly attractive for smaller developers who do not have the credit to attract recourse corporate-level debt but who do not want to give up equity in the development company.

An EPP buyer might be a financial investor with an appetite for the risks and returns of participating in a solar or wind project. Or the buyer might be a user of electricity that wants to tie up a renewable energy resource to meet both its corporate energy needs and its sustainability goals. While some large corporations have already contracted with developers to build generation facilities to meet their needs,³⁹ the EPP concept would open up this type of financing to smaller investors or electricity users.

The complex and varied regulation of electricity markets could pose legal obstacles to implementing the idea of selling forward future electricity generation. This could hamper any effort to create a national market for EPPs. An effort to develop the EPP concept, therefore, might appropriately begin in a limited number of states that are already major markets for solar generation (for example, Arizona and California) and wind generation (for example, Texas and Iowa).

Risk Allocation. The risk profile of an EPP in this development stage model has significant similarities to a VPP for oil and gas, although there are also significant differences:

- **Completion risk**—For an oil or gas property, there is a risk of the amount of commercially producible hydrocarbons at the property. A solar or wind site does not have this risk; the developer (and capital sources) can determine the amount of electricity that can be generated at the site with substantial accuracy. However, since VPPs in oil and gas are primarily based on producing (PDP) reserves, they do not have the additional “completion” risks of a solar or wind project, such as obtaining a certificate of necessity from the state regulatory authority, signing a grid interconnection agreement with the grid operator and preparing and filing an environmental impact statement.
- **Commodity price risk**—Oil, gas and electricity are commodities with significant price volatility. The buyer of a volume-denominated VPP in oil or gas or a kilowatt-denominated EPP takes the commodity price risk, which it can hedge in commodity markets. The buyer of a dollar-denominated VPP or EPP does not take commodity price risk, either in oil and gas, or in our model for electricity. The EPP buyer, together with the developer, also might mitigate the commodity price risk by signing a long-term power purchase agreement with a third-party offtaker.
- **Operating risk**—As in VPPs for oil and gas, the EPP buyer from a solar or wind developer relies on the ability of the operator of the generation facility to run it efficiently. Similar to oil and gas, the buyer can mitigate this risk by sizing the EPP interest so that there is a sufficient cushion between the amount of electricity production that it buys and the expected level of production of the completed generation facility.
- **Solvency risk**—The buyer of an EPP in a solar or wind project will not have the superior protection of an interest in real estate that purchasers of volume-denominated VPPs do in most states. However, the solar or wind buyer should be able to obtain some insolvency protection through a UCC security interest, and possibly through a bankruptcy remote structure.

EPP for Long-Term Finance. EPPs also may offer benefits in long-term financing for solar and wind generation projects. While project finance is often used as long-term financing for large utility-scale solar and wind projects, many solar projects are in the range of 25 MW at a project cost of \$30 million and wind projects are in the range of 125 MW at a project cost of \$200 million. These cost figures, particularly for solar, are below the optimal amount to justify the expense and complexity of project finance. An EPP-type structure could substitute for project finance for these smaller projects.

The smaller size at which EPP can be structured provides additional potential benefits for long-term financing. As project finance pays down over time, the project owner could use EPPs to finance upgrades and expansions of the facility. And potential suppliers of capital who are too small to play in the project finance market, such as many private equity and debt funds, could become sources of this type of capital, particularly since the smaller investment size makes it easier to diversify across projects, developers and geography.

3. Capacity Payment Finance

Generators of electricity have two potential streams of cash flow from operations—energy payments (in exchange for electricity actually delivered) and, in some markets, capacity payments (in exchange for maintaining the capacity to dispatch electricity when needed). Those regional markets that have adopted capacity payments use them as a tool to incentivize generators to invest in the capacity to meet consumer demand for reliability at peak demand times.⁴⁰ Although solar and wind power is not dispatchable, solar and wind assets may nevertheless qualify for capacity payments in some situations, in part because they are likely to be able to generate electricity during periods of peak demand. The oil and gas industry uses similar dual cash flow streams for certain types of assets, including natural gas pipelines. The different characteristics of the two types of cash flows might provide a basis to attract different capital providers and different financing terms.

Capacity Payments—Pipelines

Natural gas pipelines use a form of capacity payment as part of their revenue model. Pipeline companies typically offer customers several categories of service, one of which is a firm transportation (FT) contract.⁴¹ An FT contract provides the highest service priority. The customer pays two charges—a “demand charge” that applies even if the customer does not ship any gas through the pipeline and a commodity charge based on the volume of gas that the customer actually ships. This demand charge is a form of capacity payment, assuring the customer that pipeline capacity will be available when needed.

From the perspective of a provider of capital to finance a pipeline, the revenue streams from FT contracts have different risk characteristics:

- FT demand charge—There is no volume risk associated with this revenue, since the customer pays regardless of the volume shipped. Assuming fixed prices under a regulated rate schedule, there also is no price risk. So subject only to the credit of the customer and force majeure events, this is an assured revenue stream for the period covered by the FT contract to which a provider of capital can look to service its investment.
- FT commodity charge—This revenue stream depends on the volume of gas shipped through the pipeline, which in turn depends on supply and demand for gas. The provider of capital is exposed to this supply/demand risk. Similar to demand charges, if prices are subject to a regulated rate schedule, the capital provider does not bear price risk.

Proposal—Capacity Payment Financing for Solar and Wind Power

Historically, solar and wind power facilities have generated revenue by selling electricity under long-term power purchase agreements (PPAs) or into wholesale markets. In the years ahead, another option may be increasingly available: selling the capacity of solar and wind facilities to generate electricity into markets operated by independent system operators (ISOs). The revenue streams from the sale of capacity will have different characteristics than revenue streams from PPAs or wholesale electricity markets, which could create an opportunity in financing solar and wind generators.

Today seven regional ISOs operate electric power systems across much of the United States, managing approximately two-thirds of the country's electric power.⁴² These are ISO New England (ISO-NE), New York ISO (NYISO), PJM Interconnection (PJM), Midwest ISO (MISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool (SPP), and California ISO (CAISO). These ISOs maintain wholesale markets in which generators of electricity offer to sell energy and load serving entities (LSEs—for example, electric utilities) or offer to purchase energy, both on a spot basis and (in most markets) a day-ahead basis. These are the markets in which electricity that is not otherwise committed under PPAs or similar agreements is bought and sold.

ISOs require LSEs in their region to maintain sufficient capacity to a target level of reliability in order to meet all electricity demand plus a reserve. A market mechanism that several ISOs have adopted to achieve this objective is the forward capacity auction.⁴³ Generators, demand-side resources and storage resources bid on electric generating capacity into this market on a forward basis. LSEs make capacity payments during the capacity commitment period to all resources whose bids are accepted in the auction. LSEs make the capacity payments whether or not the system operator calls on the capacity, similar to demand charges in a natural gas pipeline.

In October 2015, ISO-NE released a discussion paper on the role of its capacity market in assuring reliability in the regional grid.⁴⁴ The ISO-NE paper suggests that capacity payments will become increasingly important, and that the share that capacity payments comprise of total operating revenues of solar and wind generators will rise from its current level in the range of 15 percent.⁴⁵ Similar to gas pipeline demand charges, developers may come to see capacity payments as the revenues that cover fixed costs and debt service.

From the perspective of a capital provider, the risk profile of capacity revenues differs from that of energy revenues. Since the capacity rating for reliability purposes of a solar or wind generator does not vary with market demand, the number of megawatts in the computation of the capacity payment is fixed. Consequently, there is no supply/demand risk associated with this cash flow stream as there is for the energy cash flow stream. And since the price for capacity for a particular commitment period is determined several years in advance, there is less overall price uncertainty and therefore less price risk than for energy payments.

These differences in the risk profile of capacity and energy payments, combined with the increasing importance of capacity payments that ISO-NE anticipates, suggest the possibility that the two cash flow streams might be segregated for financing purposes. Different investment securities could be created for capacity payments and energy payments. This could attract a broader range of investors than is possible by combining these cash flows.

Although this is worth exploring, several barriers may prevent capacity payments from becoming a reliable source of financing for solar and wind facilities:

- First, there is greater regulatory risk for capacity payments in electricity markets than for comparable capacity-type cash streams in pipelines. For pipelines, capacity payments are made under bilateral contracts between the facility operator and the customer and do not depend on a market created by regulation. In contrast, capacity payments in electricity markets depend on a market created by regulation and therefore are subject to the risk of changes in that regulatory structure.
- Second, solar and wind facilities do not offer dispatchable power, limiting their value as a capacity resource. Nevertheless, solar and wind facilities can qualify as a capacity resource in some ISOs, with discounts to nameplate capacity reflecting their limited dispatchability. Furthermore, if a solar or wind generator integrates storage in its operations, the generator could increase its capacity value. A higher capacity rating for purposes of the forward capacity market would allow the generator to increase the capacity payments it can receive from the same nameplate capacity, thereby increasing the value of capacity payments as a basis for financing.

Some capacity market designs may be more or less favorable to variable renewable technologies such as solar and wind, depending on factors such as the methodology the system operator uses to calculate the qualifying capacity (expressed as a percentage of nameplate capacity) of a generation facility. The capacity credit currently remains low in capacity auctions for solar and wind facilities that do not have integrated storage or auxiliary gas generation. For example, in its 2015 auction for the delivery years 2018–2019, PJM applied a 13 percent credit to wind and a 38 percent credit to solar PV.⁴⁶

It remains to be seen whether capacity payments to solar and wind facilities will become a sufficiently robust and reliable cash flow stream to support a separate financing tranche. As we note above, capacity payments are a regulatory creation and therefore at risk for changes in the regulatory structure. Solar and wind power's lack of dispatchability will create challenges. Nevertheless, exploring ways to segment assets and cash flows from solar and wind facilities might lead to other ideas that lower financing costs. Capacity payments offer a potential financing tool worth evaluating.

C. Next Steps

The three proposals that we present in this paper face potential hurdles to implementation that require further work to assess whether they can be surmounted. Examples of these hurdles include:

- Resource valuation for RRBF—The viability of RRBF is crucially dependent on the solar or wind resource at a site having a significant market value that can serve as collateral for financing. Studies need to be done to assess what these values may be and whether they are sufficient to support financing.
- Discounting of future values in EPP—The growth in solar and wind deployment has tended to depress power prices. Consequently, the forward sale of future production of electricity in the EPP model may need to be heavily discounted to profit from those future cash flows. Financial models need to be developed to evaluate whether the resulting payments are sufficient to serve as useful financing.
- Regulatory issues in capacity payments—Capacity payments are a regulatory creation, and their potential as a separate basis for financing is dependent in part on stable policy and continuing regulatory support. The ISOs that have capacity markets will need to evaluate the role that capacity payments might play in financing and whether the ISOs will lend support to the development of this tool.

These are just a sample of the issues that solar and wind developers, capital sources, regulators, policymakers and academics will need to explore to determine if any of these tools can in fact be implemented and will be effective in reducing the cost and increasing the availability of capital for solar and wind development.

IV. Conclusion

In the decades ahead, the capital needs of the solar and wind power industries will be enormous. If these industries can reach the scale of other, older energy sources, the potential social benefits will be substantial.

From modest beginnings early in the last century, the oil and gas industry has grown into an enormous global presence, raising hundreds of billions of dollars each year for decades. The experience of the oil and gas industry may hold valuable lessons for the solar and wind industries. New financing tools, based on those used for oil and gas development, could help solar and wind developers obtain lower cost capital.

In this paper, we propose three such tools. Additional analysis by developers, capital providers and regulators will help determine the potential of these proposals. The specific suggestions offered here are intended to be illustrative, not the end of this analysis. We welcome other proposals for ways that those seeking to finance solar and wind projects can learn from the oil and gas industry and other sectors.

NOTES

- 1 Bloomberg New Energy Finance, “Record \$30bn year for offshore wind but overall investment down” (January 12, 2017) -- <https://about.bnef.com/blog/record-30bn-year-offshore-wind-overall-investment/>; Bloomberg New Energy Finance and Frankfurt School UNEP Collaborating Centre, “Global Trends in Renewable Energy Investment 2016,” Frankfurt School of Finance and Management (Frankfurt: 2016), 14, fig. 3, http://fs-unep-centre.org/sites/default/files/publications/globaltrendsinrenewableenergyinvestment2016lowres_0.pdf. See also Michael Liebreich and Angus McCrone, “The shift to ‘base-cost’ renewables: 10 predictions for 2017” (January 18, 2017) — <https://about.bnef.com/blog/10-renewable-energy-predictions-2017/> (“Of the 18 percent drop in dollar terms, around half may have been due to reductions in the cost of equipment, as opposed to reductions in the volume of activity.”)
- 2 The numbers in the text are interpolated from data in a graph on page 52 of the report. International Energy Agency, “World Energy Investment Outlook,” (Paris, France: OECD/IEA 2014).
- 3 Ethan Zindler and Ken Locklin, “Mapping the Gap: The Road from Paris,” Bloomberg New Energy Finance, January 27, 2016, 33, <http://www.ceres.org/resources/reports/mapping-the-gap-the-road-from-paris/>.
- 4 Ben Machol and Sarah Rizk, “Economic Value of US Fossil Fuel Electricity Health Impacts,” Environment International No. 52 (2013): 75–80; Union of Concerned Scientists, “Benefits of Renewable Energy Use,” http://www.ucsusa.org/clean_energy/our-energy-choices/renewable-energy/public-benefits-of-renewable.html#.V6zwZ5grJaV
- 5 Union of Concerned Scientists, “Benefits of Renewable Energy Use,” <http://www.ucsusa.org/clean-energy/renewable-energy/public-benefits-of-renewable-power#.WLBtRiZNo4>.
- 6 International Energy Agency, “World Energy Outlook, Energy Access Database,” <http://www.worldenergyoutlook.org/resources/energydevelopment/energyaccessdatabase/>.
- 7 Lena Hansen and Virginia Lacy, “A Review of Solar PV Benefit and Cost Studies,” Rocky Mountain Institute, 2013.
- 8 Working Group III of the Intergovernmental Panel on Climate Change (IPCC), O. Edenhofer, R. Pichs-Madruga, Y. Sokona, K. Seyboth, P. Matschoss, S. Kadner, T. Zwickel, P. Eickemeier, G. Hansen, S. Schlömer, C. von Stechow (eds.), IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation, chapter 9 (Cambridge, United Kingdom and New York, NY: Cambridge University Press, 2011), 1075.
- 9 The capital envisioned here is nearly all related to the financing of assets or infrastructure—paying for the installation of power plants, storage, clean fuel synthesis or renewable heat sources—as opposed to R&D investment necessary to improve technologies. While venture and R&D investments are also necessary for progress, the deployment of significant low-carbon infrastructure requires orders of magnitude more capital.
- 10 International Energy Agency, “Energy Technology Perspectives 2015: Mobilizing Innovation to Accelerate Climate Action,” (Paris: OECD/IEA, 2015), 10.
- 11 Bloomberg New Energy Finance and Frankfurt School UNEP Collaborating Centre, “Global Trends in Renewable Energy Investment 2016,” Frankfurt School of Finance & Management (Frankfurt: 2016), 11, http://fs-unep-centre.org/sites/default/files/publications/globaltrendsinrenewableenergyinvestment2016lowres_0.pdf. This report uses the term “renewable energy.” The definition of that term in the report is comparable to the IEA definition of clean energy, although there are a few differences that make the figures from the two reports not precisely comparable. The \$329 billion investment figure includes an estimated \$43 billion in large hydroelectric projects.

- 12 Ethan Zindler and Ken Locklin, “Mapping the Gap: The Road from Paris,” Bloomberg New Energy Finance, January 27, 2016, 1, <http://www.ceres.org/resources/reports/mapping-the-gap-the-road-from-paris/>.
- 13 Ibid., 1.
- 14 Solar and wind power investment fell 16% to roughly \$226 in 2016. Ibid., 1.
- 15 This \$79 trillion figure is made up of the following numbers (and adjusted for double-counting): \$24.6 trillion managed by insurance companies, \$22.8 trillion by pension funds, \$1.5 trillion by foundations and endowments, \$3.9 trillion by sovereign wealth funds, \$30.4 trillion by investment managers, and \$11.6 trillion in nonfund pension assets. David Nelson and Brendan Pierpont, “The Challenge of Institutional Investment in Renewable Energy,” Climate Policy Initiative, March 2013, <http://climatepolicyinitiative.org/wp-content/uploads/2013/03/The-Challenge-of-Institutional-Investment-in-Renewable-Energy.pdf>.
- 16 Ethan Zindler and Ken Locklin, “Mapping the Gap: The Road from Paris,” Bloomberg New Energy Finance. January 27, 2016, 23, <http://www.ceres.org/resources/reports/mapping-the-gap-the-road-from-paris/>.
- 17 Katie Gilbert, “Will Institutional Investors Back Clean-Energy Infrastructure?” Institutional Investor, February 9, 2014, <http://www.institutionalinvestor.com/Article/3307048/Investors-Pensions/Will-Institutional-Investors-Back-Clean-Energy-Infrastructure.html>.
- 18 The numbers in the text are interpolated from data in a graph on page 52 of the report. International Energy Agency, “World Energy Investment Outlook,” (Paris, France: OECD/IEA 2014).
- 19 Ibid.
- 20 Fatih Birol, “Energy Investment for Global Growth,” presentation at the G7 Energy Ministerial Meeting, (Kitakyushu, Japan: May 1–2, 2016), 4, https://www.iea.org/newsroomandevents/speeches/160501_G7EnergyMinisterial_slides.pdf.
- 21 Proved reserves are those “that can be recovered from the deposit with a reasonable level of certainty.” Probable reserves are “those which have a 50% chance of being present.” Independent Petroleum Association of America, “Oil and Gas Reserves—Definitions Matter,” <http://oilindependents.org/oil-and-natural-gas-reserves-definitions-matter/>.
- 22 Jeffrey S. Munoz, “Financing of Oil and Gas Transactions,” Texas Journal of Oil, Gas and Energy 4 (2009): 223–267.
- 23 According to Ernst and Young, there are currently 120 publicly traded MLPs with a combined capitalization of \$600 billion. Ernst and Young, “The YieldCo Structure: Unlocking the Value in Power Generation Assets,” 2015, [http://www.ey.com/Publication/vwLUAssets/ey-yieldco-brochure/\\$FILE/ey-yieldco-brochure.pdf](http://www.ey.com/Publication/vwLUAssets/ey-yieldco-brochure/$FILE/ey-yieldco-brochure.pdf).
- 24 Richard Kauffman, “Bringing Down Green Financing Costs: How a State-Sponsored Bank Might be the Key,” http://www.frbsf.org/community-development/files/cdir_vol10issue1-Bringing-Down-Green-Financing-Costs.pdf; American Council on Renewable Energy, “Why Renewables Deserve MLP Parity,” <http://acore.org/acore-blog/item/4219-why-renewables-deserve-mlp-parity>; American Wind Energy Association, “MLP Fact Sheet,” <http://www.awea.org/Issues/Content.aspx?ItemNumber=5255>; Brookings, “Clean Energy Scores a Success with the Master Limited Partnership Parity Act,” 2013, <https://www.brookings.edu/opinions/clean-energy-scores-a-success-with-the-master-limited-partnership-parity-act/>; ThinkProgress, “Master Limited Partnerships (MLPs) Will Bring More Investment to Clean Energy,” <https://thinkprogress.org/master-limited-partnerships-mlps-will-bring-more-investment-to-clean-energy-e14ae72e44c9#.r4iyidr6b>.
- 25 Master Limited Partnerships Parity Act, S.B.1656, H.B.2883.
- 26 Citigroup Inc., “Pattern, GE, Citi Enter Texas Panhandle Wind Market,” August 20, 2013, <http://www.citigroup.com/citi/news/2013/130820b.htm>.

- 27 For example, the Massachusetts Institute of Technology recently entered into a twenty-five-year power purchase agreement with Dominion Resources, a Virginia utility, for 73 percent of the electricity production of a new 60 MW solar farm at Summit Farms, Currituck County, North Carolina. MIT purchases the electricity from Dominion Resources at a fixed price, and the electricity is resold into the PJM (mid-Atlantic) market. MIT receives the renewable energy certificates (RECs) associated with the electricity generated. MIT Department of Facilities, “MIT Solar Energy Purchase Addresses Carbon Emissions,” <http://web.mit.edu/facilities/environmental/solar-ppa.html>.
- 28 Jason Fox, Dewey Gonsoulin and Kevin Price, “Reserve Based Finance—A Tale of Two Markets, Parts 1–4,” Oil and Gas Financial Journal (January–April 2014), <http://www.bracewellgiuliani.com/assets/OGFJ%20April%202014.pdf>.
- 29 The Securities and Exchange Commission defines “proved reserves” as “those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible.” Regulation S–X, Section 210.4–10(a)(22). These regulations similarly define “probable reserves,” “possible reserves,” and other terms used in evaluating reserves for RBF loan purposes.
- 30 Jason Fox, Dewey Gonsoulin and Kevin Price, “Reserve Based Finance—A Tale of Two Markets, Part 1,” Oil and Gas Financial Journal (January–April 2014), <http://www.bracewellgiuliani.com/assets/OGFJ%20April%202014.pdf>.
- 31 Keith O’Donnell, “RBL in the Oil and Gas Sector,” chapter 17, in *The Principles of Project Finance*, Rod Morison (Gower, 2016), <http://www.gpmfirst.com/books/principles-project-finance/rbl-oil-and-gas-sector>.
- 32 Jason Fox, Dewey Gonsoulin and Kevin Price, “Reserve Based Finance—A Tale of Two Markets, Part 1,” Oil and Gas Financial Journal (January–April 2014), <http://www.bracewellgiuliani.com/assets/OGFJ%20April%202014.pdf>.
- 33 Jason Fox, Dewey Gonsoulin and Kevin Price, “Reserve Based Finance—A Tale of Two Markets, Part 2,” Oil and Gas Financial Journal (January–April 2014): 149–179, <http://www.bracewellgiuliani.com/assets/OGFJ%20April%202014.pdf>.
- 34 Ibid.
- 35 AJ Akaydin and Christina Kitchens, “Current Trends in Oil and Gas Finance and Risk Management,” October 15, 2015, http://cymcdn.com/sites/www.dallasafp.org/resource/resmgr/2015_Presentations/10.15.14_DAFP_Current_Trends.pdf.
- 36 Robert Rabelais and Matthew Einbinder, “Chapter 11, Oil and Gas Reserve-Based Lending,” *The International Comparative Legal Guide to Lending and Secured Finance 2014*, 2nd ed. (London: Global Legal Group, 2014), http://www.stblaw.com/docs/default-source/Publications/the-international-comparative-legal-guide-to-lending-secured-finance-2014-edition_chapter-on-oil-and-gas-reserve-based-lending.pdf.
- 37 Ibid.
- 38 Jeffrey S. Munoz, “Financing of Oil and Gas Transactions,” *Texas Journal of Oil, Gas and Energy* 4 (2009): 223–267.
- 39 Apple committed \$850 million to finance a 280 MW solar PV project being developed by First Solar in Monterey County, California, and will have the rights to 130 MW of that capacity under a twenty-five-year PPA. First Solar, “California Flats Solar Project,” accessed July 23, 2016, <http://www.firstsolar.com/en/About-Us/Projects/California-Flats>.
- 40 There is extensive literature that describes the market failures that capacity markets are designed to address. Demand for electricity is very inelastic, due in part to the lack of availability of real-time pricing information to most customers and to the lack of systems that would allow customers to respond quickly to price changes. Consequently, when there is high demand and scarcity of electricity, the market is unable to establish a market clearing price that would assist the market in determining the efficient level of resources and mix of generation types. Peter Cramton, Axel Ockenfels and Steven Stoft, “Capacity Market Fundamentals,” *Economics of Energy and Environmental Policy* 2, No.2 (2013): 1–21.

-
- 41 Transco, “Contracts Overview,” October 30, 2012, accessed June 20, 2016, <http://www.1line.williams.com/Transco/files/training/ContractsOverview.pdf>.
 - 42 Federal Energy Regulatory Commission, “Electric Power Markets: National Overview,” February 29, 2016, <http://www.ferc.gov/market-oversight/mkt-electric/overview.asp>.
 - 43 PJM, MISO and NYISO, among the seven regional ISOs, also operate capacity markets that use somewhat different mechanisms from ISO-NE.
 - 44 ISO New England, “The Importance of a Performance-Based Capacity Market to Ensure Reliability as the Grid Adapts to a Renewable Energy Future,” October 2015, http://www.iso-ne.com/static-assets/documents/2015/10/iso-ne_discussion_paper_-_capacity_market_and_renewable_energy_future_-_revised_version_-_10-30-2015.pdf.
 - 45 In ISO-NE in 2015, the capacity market was \$1.1 billion out of a total wholesale electricity market of a little more than \$7.0 billion. ISO New England, “How Energy Storage Can Participate in New England’s Wholesale Electricity Markets,” March 2016, http://www.iso-ne.com/static-assets/documents/2016/01/final_storage_letter_cover_paper.pdf.
 - 46 Thomas Jenkin, Philipp Beiter and Robert Margolis, “Capacity Payments in Restructured Markets under Low and High Penetration Levels of Renewable Energy,” National Renewable Energy Laboratory Technical Report NREL/TP-6A20-65491, February 2016, <http://www.nrel.gov/docs/fy16osti/65491.pdf>.

