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Roadmap to a Low Carbon Electricity System in the U.S. and Europe

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About CPI

Climate Policy Initiative (CPI) is a team of analysts and advisors that works to improve the most important energy and land use policies around the world, with a particular focus on finance. An independent organization supported by a grant from the Open Society Foundations, CPI works in places that provide the most potential for policy impact including Brazil, China, Europe, India, Indonesia, and the United States.

PREFACE

For more than a century, reliable electricity has been a foundation of the modern economy. In the 21st century, the electricity system will be even more important as it will deliver more of our energy needs and provide a path to reducing carbon emissions by incorporating low carbon energy supplies. Yet an effective and relatively low cost transition requires change across every electricity industry business segment, from generation to transmission, market operation, distribution and even customer management.

This paper outlines the challenges each business segment will face and sets out a roadmap for addressing these challenges.

- For energy regulators, planners, and policymakers, it identifies the key technical and financial issues that need to be resolved and provides initial hypotheses around what might be the most fruitful directions to pursue.
- For environmental regulators, it provides a framework to guide the development of efficient regulation that steers the industry toward a lower cost, lower carbon path.
- For financial regulators, it explains new investment products that could become an important part of institutional investor portfolios.
- For investors, banks, utilities, and other businesses, it provides insight into future business opportunities that may arise, as well as areas where change and risk may prevail.

This paper is a first step in a body of work CPI is developing around each of these challenges. In Part I we set out the challenges and an initial glimpse at key characteristics of a future system. In Part II, we begin the deeper analytical exploration, delving into the financing of renewable energy and exploring business models that can harness the investment power of institutional investors and energy consumers alike to reduce the cost of our future low carbon energy system. In future works we will address customer management, transmission, distribution, and, importantly, how all of these new business fit together and what that might mean for the financial viability of current and future utilities and other related businesses.

INTRODUCTION

Since Thomas Edison established the first investor-owned electric utility in the 1880s, the electricity supply industry has grown and become a central pillar of an efficient, modern economy. Today, electricity generation, transmission, distribution and the factories, businesses, and appliances that use the electricity represent trillions of dollars in investment around the world.

> *The electric supply industry is a 19th century invention that needs to transition to the realities of the 21st century*

However, the system is on the brink of a transition. Increasingly cost-competitive renewable energy technology, pressing environmental concerns, and changing customer needs are transforming how we make and use electricity. The need to restructure and decarbonize electricity industries is arguably the biggest climate change related challenge facing developed countries. A major overhaul of electricity industry design, along with hundreds of billions of dollars in new investment, is needed to make the electricity industry structure fit for the clean and efficient economy of the 21st century.

With so much history and investment at stake, restructuring to support the transition to a low carbon energy system will be difficult. However, without a clear path to a better structure, uncertainty will make meeting the growing investment requirements that much more difficult and expensive. We thus sit at an important juncture in the future of electricity supply. We can minimize the cost of this transition with a clear vision for the future industry model and a transition path that addresses financing requirements, leverages the existing industrial structure to meet increased flexibility needs, and facilitates integration of customer-generated electricity. Without this vision, electricity supply could become more expensive, more difficult to finance, less reliable, and may stay relatively carbon intensive.

Developing this vision — and getting the political buy-in to pursue it — is, in itself, a task that should not be taken lightly. The electricity supply industry is complicated, with a host of technological, regulatory, and economic practices and considerations to take into account. The good news is that there are many good ideas from which to

Key CPI Analysis Questions

1. How does the current industry structure and financing model affect the cost of large-scale low carbon electricity generation?
2. What could a new industry structure and financial model look like?
3. How would a new model lead to lower renewable and nuclear energy costs?
4. What are the costs and obstacles of a transition to a new model?
5. How can financial, energy, and environmental policy facilitate a cost-effective path for the electricity sector's transition?

build a solution — and many companies and jurisdictions have begun implementing some of these ideas. In this series, CPI presents a vision that fits all of these pieces together, a transition roadmap that accounts for future needs and provides policymakers with guidance on how they can help.

In opening our discussions, CPI presents this overview to outline the new challenges facing each of the five main electricity industry business segments and possible transition pathways for the future electricity system model.

In the second upcoming part of this series, we look in more depth at an important catalyst of the transition to a low carbon energy system: finance. As a basis for future CPI work, we describe the financing of new business models for each segment of the electricity sector. We focus on the finance of low carbon energy sources, explaining why current models increase the cost and make these investments less accessible and attractive to potential investors, including institutional investors. We then lay out CPI's vision for financing low carbon energy as infrastructure, where companies, municipalities, and even individual households might invest in generation infrastructure as a way of purchasing a long term supply of energy, thus aligning the product with the financing decisions, and in so doing lowering financing costs. We believe that a move towards this model could reduce the cost of low carbon electricity infrastructure by at least 20%, and thus could be the catalyst to a more efficient, cleaner industry.

More broadly, CPI's work on energy finance, institutional investors, and energy transitions suggest a model that may involve a much more disaggregated set of companies, operating under a variety of regulatory and competitive regimes and employing an array of financing models. New models for providing transmission, energy balancing, distribution, transmission, and even energy efficiency finance will evolve, as will new models to finance each of these businesses. In this and future work, CPI aims to assess and analyze the best paths towards a new, clean, and efficient industry.

Part I: Overview

CURRENT CHALLENGES FACING THE ELECTRICITY SUPPLY INDUSTRY

The starting point for a transition is a large, complex, and fragmented industry, with massive sunk investments and firmly established operating practices

This evolution will not be easy. The U.S. and European electricity industries represent huge investments that underpin economic stability and growth. In the U.S., the industry has evolved mainly through the efforts of publicly traded investor-owned utilities (IOUs) regulated on a state-by-state basis, interspersed with municipal and federally-owned companies. Over the last 30 years, regulators have opened competition in generation, creating the space for independent power producers (IPPs) that compete to supply energy to the grid and electricity customers. In many European countries, the mix also includes IOUs and municipal utilities, but many countries also had national state owned utilities that dominated their respective industries. Most of the state-owned utilities have now been fully or partially privatized, and in many cases the sector has been completely revamped to provide for greater competition and efficiency.

Over time, competing business models have evolved to co-exist, and regulation has helped all these entities work together to provide reliable and reasonably priced electricity. Yet the sheer complexity of the industry, and the vast number of players involved, has created a set of customary business practices and entrenched interests that encumber the industry with a great deal of inertia. Across the U.S. and Europe, we see transmission systems that cannot be reorganized due to incumbent fears of losing competitive advantage, power plants that cannot be shut down due to local employment or tax base concerns, and new technologies that are more expensive, because they must adapt to the current business structure rather than vice versa. These are all examples of inefficiencies that have crept in over the 130 years of electric utility development.

Governments and industry regulators have pushed to remedy these inefficiencies, sometimes with notable success, but just as often, success has been limited by the inertia of incumbents and the concern that any change to the system could jeopardize reliability. The result is that utility industry structures evolve slowly, often lagging decades behind technological and economic realities.

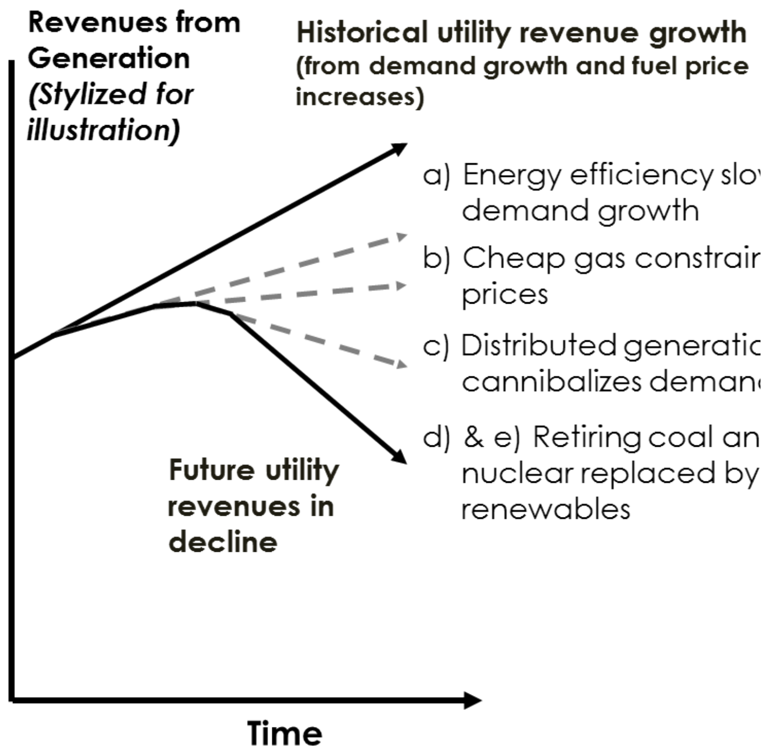
Now the imperative for rapid system evolution is stronger: Today's industry features have developed around a slowly growing industry dominated by large-scale, fossil-fueled power plants, where power plants can be centrally dispatched (turned up or down) to meet fluctuating loads, and power is passed through a transmission and distribution network to the homes and factories that need the electricity. The momentum of new low carbon technology and environmental concerns suggest that none of these historical patterns — slow but steady growth, dispatchability, or dominance of large-scale centralized generation — are certain characteristics of the electric utility industry going forward.

The growth of low carbon technologies is one of several long-term trends that threaten the viability of the industry as it is currently structured (see Box 1). Together, these trends simultaneously threaten to curtail demand growth, introduce new sources of competition, and increase the cost and technical difficulty of serving the demand that remains to be met by the large incumbent utilities.

Investors in the equity markets have already woken up to the potential plight of investor-owned utilities in the U.S. and Europe. Over the last six years, utility company shares have underperformed the general market by around 30% in the U.S. and 40% in Europe (See Figure 1).

Not only is this bad for current utility investors, it is also potentially bad for the economy and the environment. As their revenues and profits fall, many utilities can no longer support the levels of debt to which they have been accustomed. To reduce their debt levels, they need to sell assets and businesses, reduce investments to save cash, or raise new equity. With utility share prices low and unattractive, raising new equity becomes very expensive (they have to sell more of the company and its future cash flows to raise the same amount of cash). So, their only option is to slow growth and shrink.

BOX 1: Trends driving a decline of conventional utility generation models



Slowing demand growth — driven by energy efficiency, rising commodity prices, technology improvements and a slower growing economy — which reduces growth opportunities

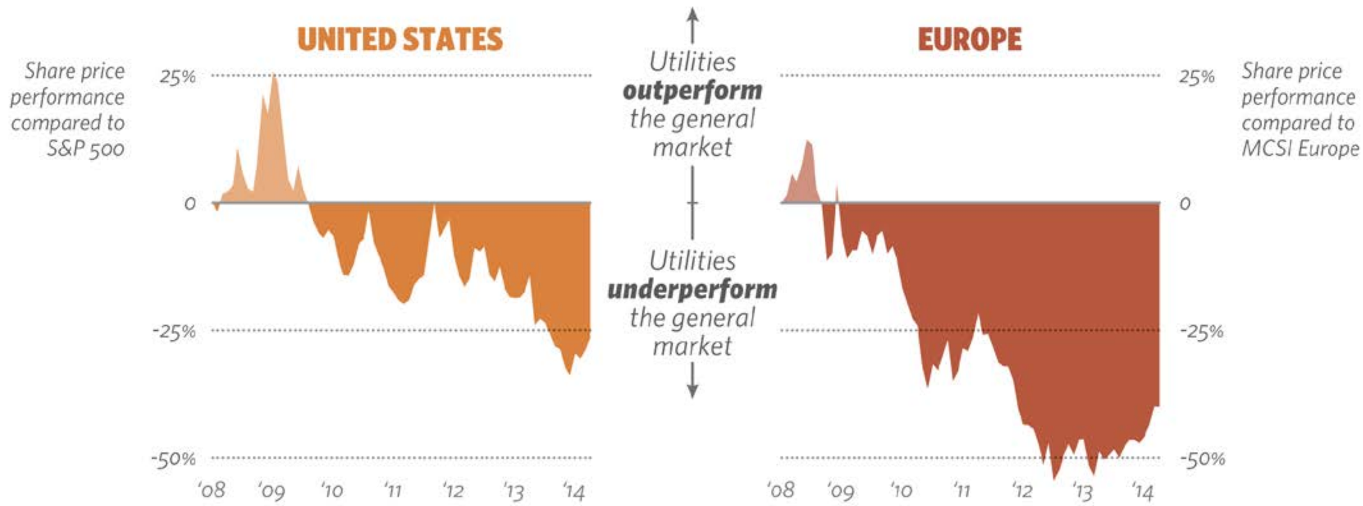
Increasing distributed generation such as rooftop solar or cogeneration for industrial and commercial electricity consumers, which may further erode the share of generation of the large incumbent players and change the economics of the energy distribution system

Regulation of carbon and coal-fired power plants, which is changing the generation mix and the relative economics of generation fleets, potentially to the detriment of many incumbent utilities

The emergence of cheap gas in the U.S. is adding further pressure not only to coal, but also to other sources of generation such as nuclear

The increase in renewable energy and its rapidly improving economics: Renewable energy can further crowd out some existing generation, but with its intermittent output, it can put a higher premium on standby and flexible generation and alter needs and operation of the transmission system

Figure 1 Share price performance of U.S. and European utilities



The falling investment and slower growth comes at a time when precisely the opposite is needed to meet environmental goals and maintain system reliability. The International Energy Agency (IEA) estimates that the global power sector will need US $2.8 trillion in incremental investment to achieve a 2°C pathway. This is in addition to the US $12.4 trillion needed in a business-as-usual scenario (International Energy Agency 2012).

The transition to an efficient low-carbon electricity supply industry must address challenges in each of the five main electricity business segments.

While replacing an aging, fossil-fuel generation fleet may seem the most obvious challenge to achieving a new low-carbon electricity supply industry, it will not be enough. Integrating renewable energy at scale into the existing industry structure, built around the operational and financial characteristics of a fossil-fuel driven system, will be very expensive and may not work at all. Market operations, grid system design, and utility incentives in the long term could easily exceed original investment costs. To make a successful transition, each of the five major business segments of the integrated utility model — generation, transmission, market operation, distribution, and customer service — face major challenges and requirements for new investment and restructuring. To meet them, they must:

Generation – Update business models to reduce renewable financing costs and focus conventional generation on providing grid flexibility

Transmission – Better integrate renewable energy by consolidating transmission ownership and coordinating its operation across states

System balancing and market operation – Update markets and business models to promote investment in flexibility resources for a low-carbon grid

Distribution – Develop new models for financing and operating distribution systems to adapt to changing demand patterns and new distributed energy and flexibility resources

Customer Management – Facilitate the increasingly active role of customers in the electricity sector

Addressing many of these challenges will provide value whether or not we choose a low-carbon path. However, transition to a low carbon energy system will be impossible, or impossibly expensive, without addressing these challenges.

Table 1 Significant challenges face each traditional utility business segment

Traditional Utility Business Segment	Significant Challenges
Generation Historically, electric utilities have built large, centralized generation in order to maximize efficiency and economies of scale. Much of this generation is based on fossil fuels and is dispatchable, where output can be adjusted to meet fluctuating demand	Financing large, utility scale, low carbon energy projects including renewable energy and nuclear
	Adapting to a shrinking market for conventional, fossil-fuel generation
	Increasing the flexibility provided by remaining fossil-fuel generation to compensate for intermittency and lower flexibility of renewable energy supplies
	Meeting new environmental requirements and regulation
Transmission Output from large generators is moved at high voltage to the factories and distribution systems feeding households and businesses	Reorganizing the ownership and operation of the transmission grid to increase the efficiency, flexibility, and reliability of the system
	Incentivizing new investment in transmission and storage to adapt to changing generation and consumption patterns
System balancing and market operation System operators provide low-cost and reliable electricity by selecting the optimal mix of generators and transmission at any time (and/or operating markets to provide incentives)	Responding to the higher penetration of intermittent generation by integrating new sources of flexibility and balancing, including more energy storage and greater customer response and participation in the market
	Providing appropriate incentives both to bulk clean energy providers and flexibility and balancing service providers
Distribution Distribution systems take electricity from the high-voltage grid, reduce voltage, and deliver it to consumers. Historically, these flows have been mainly from the central system to the consumer	Accommodating a higher penetration of generation and storage embedded in the distribution system and consumption that can be dispatched (for instance electric vehicles) to produce efficient and reliable operation of the local grid
	Developing new models for pricing and financing local grid services as local demand declines in regions where many customers supply their own energy needs
Customer Management Utilities collect consumer information and consumption data, bill customers, collect payments, and provide a number of other customer services	Gathering and processing increasingly complex data as customers both supply and consume energy and adjust demand in response to local price signals
	Incorporating new demand side technologies and services (e.g. vehicles) into customer service and billing regimes
	Developing new energy efficiency and distributed energy finance mechanisms
	Creating entirely new companies and institutions as consumers opt out or join alternative energy aggregators and service providers

A ROADMAP FOR THE LOW CARBON TRANSITION

The biggest challenge: creating and implementing an integrated plan

The challenges outlined here are not new. Work in each of these business areas is well underway. However there is a long way to go from a set of ideas to solve individual problems to a cohesive plan to restructure the industry. CPI's work integrates financial and policy solutions to the specific challenges, and fits the solutions together.

This kind of integrated thinking is crucial. The model that emerges for financing renewable energy and treatment of distribution will affect the transmission grid. Consumer behavior affects the entire sector, and the central balancing market, as the clearinghouse for each of the activities, must respond to every element. It would be impossible to change one element without having a significant impact on all of the others.

Taking some of the most promising solutions under discussion today, we can sketch the outline of a future electricity industry (see Figure 2). The outlined industry structure implies major changes for each of the traditional business segments. Many of these changes are extensions of industry reforms of the last 30 years: opening generation up to competition and independent power producers across the U.S. and Europe; creating locational price signals and tradable transmission rights, such as in the PJM market in the U.S.; and opening up customers to competition by allowing them to select their electricity supplier. However, the reform paths will be altered and accelerated by the evolving technology, economic and environmental trends, and requirements.

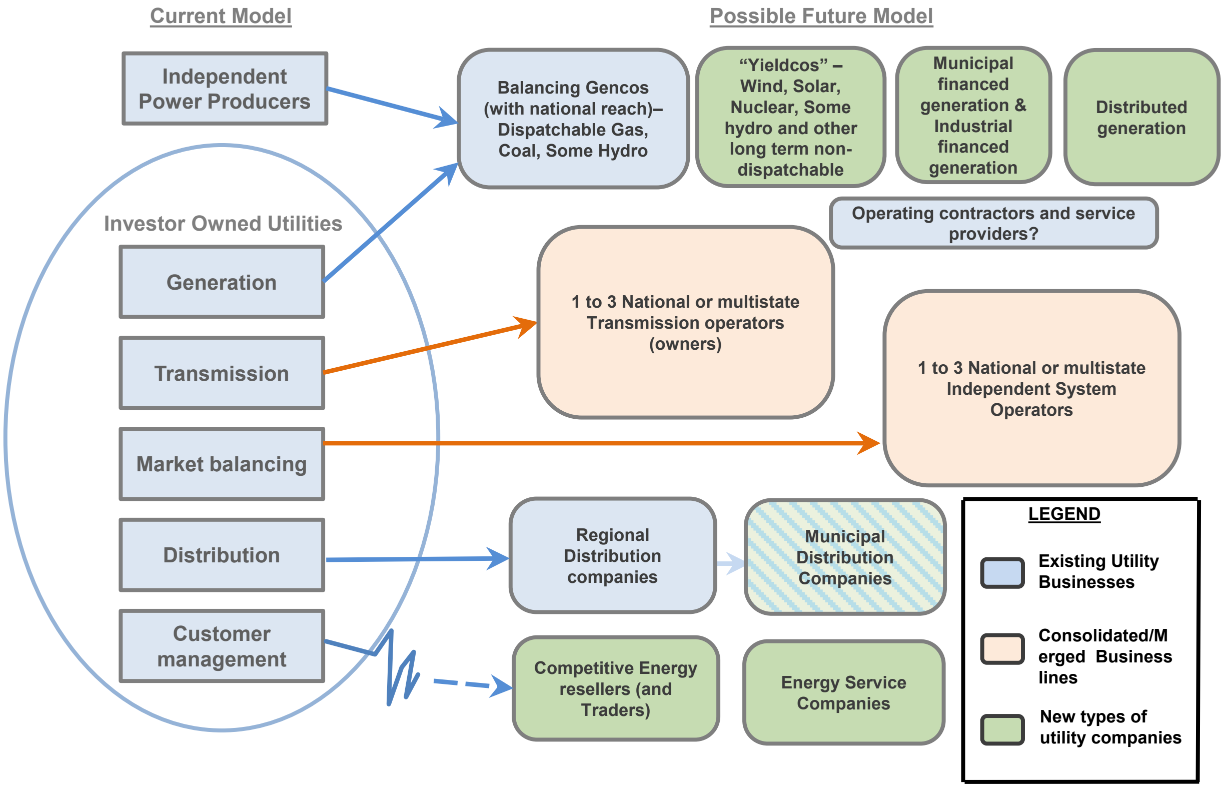
In the following sections, we detail a roadmap for each of the traditional utility business segment in turn.

CPI's role

Our work in this area will cover all of these challenges which affect the deployment of renewable energy. In particular, we offer an integrated plan that addresses the interrelationships among these components.

Initially, our work will focus on the role of investor-owned utilities in the financing of renewable energy. With renewable energy likely to comprise a growing proportion of generation in both Europe and the U.S., how these utilities respond to the growth of renewable energy and the incentives they are given could well determine the shape of the entire industry in years to come.

Figure 2 Current and potential future structure of the electricity supply industry



Generation: New business models to reduce renewable financing costs and focus on using conventional generation to provide grid flexibility

Traditional Utility Activity	Challenges
Historically, electric utilities have built large, centralized generation in order to maximize efficiency and economies of scale. Much of this generation is based on fossil fuels and is dispatchable, where output can be adjusted to meet fluctuating demand	Financing large, utility scale, low carbon energy projects including renewable energy and nuclear
	Adapting to a shrinking market for conventional, fossil-fueled generation
	Increasing the flexibility provided by remaining fossil-fuel generation to compensate for the intermittency of renewable energy.
	Meeting new environmental requirements and regulation

Large, utility-scale generation will continue to play a role during a transition to a low carbon electricity system. However, less of it will be fossil-fuel based and less of it will provide dispatchable, flexible output. The remaining flexible, mainly fossil-fuel generators will increasingly be valued more for their flexibility than for their actual energy output, which comes with the associated carbon emissions. Current generation business models are based in part around optimizing fuel choice and availability to maximize output at a minimum of fuel costs within the constraints of system peaks and troughs. These models are outdated when a large share of generators have no variable fuel costs, while those that do have fuel costs are valued for their flexibility rather than generation alone.

New business models will need to reflect these changes. Incentives and business structures can be revamped to reflect incentives that make sense for the new types of generation, driving them to reduce capital and financing costs as well. The new models would reflect changing risk and performance expectations for both old and new generation sources and could lead to significant reductions in financing costs thus reducing the cost of the new electricity model (discussed in detail in the second paper in this series). Six new types of business models and company/investment structures may play a role for the large-scale generation of the future:

YieldCos: New infrastructure style companies or funds will become the owners of non-dispatchable, larger-scale low carbon generation such as wind and nuclear. These assets will be owned by institutions and other investors seeking steady, predictable, bond-like returns. We explain the advantages of such a model, including the substantial financial benefit, in the upcoming Part II of this series. YieldCo vehicles have already begun to emerge in 2013, with NRG's spin off of a YieldCo and UK's Greencoat Wind fund's initial public offering. However, as we discuss in greater detail in the second paper in this series, these examples are not yet structured in a way that fully take advantage of the bond-like returns these projects can provide.

Municipal and industrial owned and financed generation, where long term low carbon energy supplies are purchased directly from developers. For companies, this provides long-term energy price certainty, while for municipalities it can leverage lower cost financing to provide energy to meet its own needs and supply those of its residents.

Crowdsourced energy investment where consumers can buy shares of generating units or companies and receive payments as a share of energy rather than financial return. This idea is in early stages as significant legal and regulatory obstacles remain, but the longer term benefit for consumers to purchase fixed price, long term energy supplies (and potentially bundle the supply with a property) could make the system attractive.

Distributed generation, particularly in the form of rooftop solar, is already becoming a very attractive supply option for households and commercial establishments alike. It leads, however, to operational and investment challenges, which we discuss later.

Generation operation and service companies will emerge to operate and maintain power plants as contractors, rather than owners. As ownership of generation becomes more dispersed and new companies emerge to operate and maintain systems for passive owners, this new class of companies could flourish—and in doing so, achieve economies of scale and learning.

Balancing generation companies (Balancing GenCos) will play an increasingly important role in a future dominated by intermittent renewable energy. They will focus on providing balancing services using flexible fossil-fuel and hydroelectric generation and storage systems. The majority of their profits will be derived from their flexibility rather than the units of electricity provided.

Transmission: Reorganize to better integrate renewable energy

Traditional Utility Activity	Challenges
Output from large generators is moved at high voltage to the factories and distribution systems powering homes and businesses	Reorganizing the ownership and operation of the transmission grid to increase the efficiency, flexibility and reliability of the system
	Incentivizing new investment in transmission and storage to adapt to changing generation and consumption patterns

Separating transmission from generation and operating the transmission assets through a small number of entities covering large geographic extents can improve coordination and efficiency, enable better integration of intermittent energy by gathering a diversity of supply sources, and level the playing field for new generation technologies. This has long been the goal of regulators and policymakers in both Europe and the U.S., but has only partially been realized. With the advent of more cost-competitive renewable generation requiring transmission, the benefits of such a transition will be harder and harder to ignore.

Energy markets and balancing systems: Update markets to promote efficient investment in grid flexibility resources

Traditional Utility Activity	Challenges
System operators provide for low cost and reliable electricity by dispatching generation and transmission (or providing appropriate incentives) based on cost and transmission constraints	Responding to the higher penetration of intermittent generation by integrating new sources of flexibility and balancing, including more energy storage and greater customer response and participation in the market
	Providing appropriate incentives both to bulk clean energy providers and flexibility and balancing service providers

Energy markets and balancing systems have been at the core of efficiency improvements and competitive generation over the last 30 years. Some have been very successful under various designs at improving dispatch, reducing costs, and enhancing competition. However, the designs have largely been based around competition between fossil-fuel generators, with hydroelectric generation benefitting from the flexibility it offers and nuclear generators acting as price takers in these markets.

The increased emphasis on the bulk purchase of power from renewable energy, along with the increasing value and sources of flexibility, will create new challenges for these markets. Expanded networks and resource differences may place additional value in markets with locational pricing. One result may be a separation of bulk power markets from balancing service markets, with a smaller number of system operators overseeing larger and more complex markets. In any scenario, significant market design enhancement and adaptation is needed.

Distribution: New models to enable deployment of customer generation and storage while maintaining grid services

Traditional Utility Activity	Challenges
Distribution systems take electricity from the transmission system, reduce voltage, and deliver it over a lower voltage grid. Historically, these flows have mainly been from the central system to the consumer only	Accommodating a higher penetration of generation and storage embedded in the distribution system, as well as consumption that can be dispatched (for instance electric vehicles) to produce efficient and reliable operation of the local grid
	Developing new models for pricing and financing local grid services as local demand declines in regions where many customers supply their own energy needs

Customer-generated electricity, from sources such as rooftop solar, is growing rapidly; countries and states are eager to maximize opportunities to reduce emissions while benefitting many consumers. However, the growth of distributed generation creates operational, investment, and pricing challenges for the electricity distribution system. Pricing models are already under threat. Tiered tariffs and net metering in places like California are creating incentives for the largest consumers to install distributed generation. In so doing, an increasing share of distribution costs fall on an increasingly smaller segment of consumers. However, altering the pricing model could make new distributed energy less attractive to build and so undermine other efforts needed for a low carbon energy system.

Meanwhile, the increase in distributed generation, and, eventually, the increase in electric vehicle charging, will change the operational characteristics of distribution systems, requiring additional investment, more active management, and increasingly heavy data gathering and complex pricing, all at a time when some consumers are leaving the grid. Rocky Mountain Institute envisions a time when storage and distributed generation will be cheap enough for homes to leave the distribution grid entirely, potentially upending the entire business (RMI 2013).

The end game will probably be a conversion of distribution services from energy supply to infrastructure, load balancing and backup services, and for distribution services to be priced on that basis. In many cases, it may make sense for distribution systems, at least at the more local levels, to be built, managed, and paid for as infrastructure rather than energy. Thus, community ownership may be an attractive model.

Customer management: Facilitate active role of customers in the electricity sector

Traditional Utility Activity	Challenges
Utilities collect consumer information and consumption data, bill customers, collect payments, and provide a number of other customer services. Many regulated utilities also run energy efficiency programs funded by ratepayers.	Gathering and processing increasingly complex data as customers both supply and consume energy and adjust demand in response to local price signals
	Incorporating new demand-side technologies and services (e.g. electric vehicles) into customer service and billing regimes
	Developing new ways to finance energy efficiency and distributed energy in the context of a restructured industry
	Creating entirely new companies and institutions as consumers opt out or join alternative energy aggregators and service providers

No segment more typifies the challenges and potential benefits of new business models for electricity than the interaction between customers and electricity providers. For decades, from the customer's perspective, the mark of a good electricity supplier has been one that provided reliable electricity whenever the customer demanded it. Customers seldom thought of the costs that they imposed on the system due to their usage patterns. While decades of utility and government sponsored energy efficiency, demand side management, and demand response programs have sought to address this issue, with some success, the overall impact has not been transformative. From the generator's perspective, it has just been easier — and sometimes more lucrative — to continue building and operating more flexible generation. From the billing and customer service perspective, tracking customer electricity use in a way that encourages energy efficiency and price-responsiveness has been too difficult. From the consumers' perspective, the potential savings may not have been sufficient to overcome barriers and motivate action.

Several things are changing. We have seen that, from the generator's perspective, the call on flexible generation is becoming greater and potentially more costly. But it is in the customer service and consumer side that the most interesting changes are taking place. Advances in smart metering and information technology are providing new avenues to monitor and evaluate customer use and savings. Meanwhile, customers have new end uses (like electric vehicles), greater potential control (due to advances in information technology), their own sources of generation (like solar panels), and in the near future, possibly their own storage. When all of these are wrapped together, customers will have both more control of their energy uses (for instance, by controlling when they charge their vehicles or their energy storage systems), and more information and options to do so.

As the utilities evolve, there should be more room to supply the range of services customers may find attractive and to integrate electricity services into a range of other businesses. For example, new businesses could take advantage of emerging technologies and smart meter data to turn historically passive consumers into active ones. New businesses could offer packages of services such as energy efficiency, distributed generation, and payments for grid services, helping customers benefit from participating as both consumers and service providers in more efficient energy markets. These businesses might even sell electric vehicles, bundled with distributed generation, sophisticated energy use monitoring and flexibility software, charging stations, and energy storage. And with these new companies, and the scale of new equipment and services potentially on offer, new financing models could emerge to reduce the costs of implementing the host of distributed generation, energy efficiency, and flexibility products that will be on offer.

Putting the pieces together: A model for the low carbon electricity system

Will the new model — and the transition — be financially viable?

If each business segment transforms in the ways detailed above, investor-owned utilities will have changed beyond recognition. There will no longer be any imperative or significant advantage for the same company to generate, distribute, and deliver electricity. Yet some of the scale lost from this de-integration could be gained through geographical aggregation. We might see companies that own only balancing generation or transmission, but these companies would own much more of each over wider geographic spreads. Individuals, municipalities, and investment funds would also own more of the system, but with this split of ownership, there will be a greater need for service companies to provide the operation, construction, and maintenance services that will be needed. On the commercial end, there may be more opportunities to wrap energy retail and service delivery up with services across a wide range of industries.

Some questions about this model, and the transition to it, remain. How can these new types of companies thrive? Would they have the financial wherewithal to deliver these services and do so in a cost effective manner? And how would nations and states transition to this new set of businesses and companies?

Once the viability of the model is certain, additional questions must be asked to refine the industry design. What policies are most cost-effective in encouraging deployment of renewable energy? How do regulators ensure reliable electricity with a portfolio that's high in renewable energy generation? What policies and regulations maximize the flexibility of the system? What risks would specific types of investors take, and what returns might they require?

We need to know how each of these businesses would fit into the existing landscape of investors, and how to encourage investment. We need to understand how each of these new businesses could develop and whether they would safeguard the industry knowledge while retaining financial solvency.

To answer these questions, we need to estimate the size and market for all of these opportunities, and to explore potential business and regulatory structures to see how much they would cost and whether or not they could attract finance at a reasonable cost. Putting this together, we can then begin to evaluate the paths for transition, and to identify what government, regulators, utilities, and investors could do to make these paths more effective.

Our analysis shows that the financing of large-scale, low carbon energy is one of the potential catalysts to accelerating this transition. In Part II of this series, we look more deeply into the issues with financing models and industry structures typically used to finance and invest in renewable energy. We then identify the requirements and options needed to make finance more effective.

Part II: Financing Renewable Energy

The Challenge and Opportunity of Renewable Energy Finance

Part I of this series describes the key challenges facing the U.S. and European electricity supply industries in their transition to a low carbon system. Among these challenges, the cost and structure of renewable energy finance most clearly demonstrates the inadequacies of the existing industry structure and the benefits that could be achieved by moving toward a structure more aligned with the characteristics of low carbon generation. Addressing renewable energy finance and creating business and regulatory structures to reduce financing costs can catalyze the smooth and cost-effective transformation of the industry.

Business models to date support fossil fuel energy's risk-return requirements

Investor-owned utilities (IOUs) and independent power producers (IPPs), the companies that build and finance the majority of power plants in the U.S. and Europe, have developed their corporate and finance structures primarily around fossil fuel generation.[1] Operating fossil fuel plants requires managing important risks associated with fuel prices, dispatching plants, scheduling downtimes for maintenance, and making capital investments to extend plant lifetimes.

Investors in IOUs and IPPs have demanded a premium to compensate for these additional risks. On the corporate side, companies earn the premium by managing these risks successfully. Higher returns give companies incentives to lower costs through effective risk management of power plants, contracts and systems, with the expectations that these lower costs will more than offset the higher cost of capital.

Different regulatory and market structures have developed to limit risks to investors in order to keep financing costs reasonable. For instance, price regulation — and sometimes national ownership — transfers many of the risks back to consumers or taxpayers. In the 1990's a wave of deregulation, restructuring, and privatization swept through the electricity industry in the U.S. and Europe, opening up power generation to competition, with this increased competition providing incentives for companies to lower costs and improve how they managed risk. The result was a significant reduction in overall system costs, but there was a tradeoff as investors demanded higher returns to compensate for the risks that were shifted from ratepayers back to investors. While competitive markets have improved the cost performance of fossil-fuel generation, they have also made it more difficult and expensive to finance nuclear, hydroelectric, and renewable energy.

Project finance and corporate finance: models for fossil fuel generation

One consequence of deregulation has been the emergence of the project finance model for financing power projects. In the project finance model, a developer sets up a company consisting solely of the particular asset or project. This project company can then borrow money against the expected cash flows from the project. Project finance reduces the risk to the

[1] These companies have also built nuclear, hydroelectric and renewable generation, but fossil fuel generation has been the mainstay.

owner/developer, since the lender has no "recourse" to the parent company's finances; that is, if the project cannot meet its debt obligation, the lender can take over the project but cannot require the owner to make up for the debt shortfall, limiting the liability of the owner.

Most large, utility scale renewable energy projects are currently financed either using project finance or through corporate finance, where an IOU or IPP uses its own equity and borrowing power at the corporate level. Typically, the IOUs and IPPs evaluate all projects using project finance criteria, even when using their own corporate resources. In Section 2.3 of this brief, we will discuss how the use of IOU corporate finance increases the cost of renewable energy by imposing the corporation's financial requirements on the investments, thus diluting and obscuring the underlying characteristics of the project and, in this case, raising financing costs.

If the electricity industry started from a clean slate, with the objective of financing renewable energy at the lowest cost, it would certainly not use the same corporate models and finance structures. The mismatch is clear.

Renewable energy, on its own, has no fuel price risk. Nonetheless, in fossil fuel-based competitive markets, it has an even greater exposure to fuel price risk than fossil fuel generators. Fossil fuel generators are often partly hedged against market volatility. Their own costs drop when falling fuel prices drive down wholesale electricity prices, while renewable energy must bear the entire risk of volatile prices. This risk increases uncertainty for renewable energy projects and raises financing costs.

Renewable energy is not dispatchable (it cannot be turned on or off as needed), but investors in IOUs and IPPs expect a premium to manage risks associated with dispatch for their fossil fuel plants. This premium when applied to renewable energy projects translates into higher costs.

Renewable energy has high investment costs but low operational costs, making it much more sensitive to financing costs.

Most importantly, investors in IOUs and IPPs demand the same types of return from their renewable energy projects as from conventional generation, even though these have a very different risk profile. With current business and investment models, renewable energy costs have to rise to make renewable investments attractive to utilities and to make investment in the shares of IOUs and IPPs attractive to the financial markets. We will show that **new investment vehicles designed around the unique financial characteristics of renewable energy could reduce its costs by up to 20%.**

Table 2: Institutional investor requirements are a good match to the financial characteristics of renewable energy generation projects

	Typical Renewable Energy Project Characteristics	Typical Institutional Investor Requirements	Typical Utility Business Characteristics
Cash flows	Similar to bonds High upfront capital costs followed by small ongoing costs	Bond like for most investment Looking for bond like predictable long term cash flows	Low risk equity with moderate capital costs; income variable depending on fuel prices and dispatch
Opportunities for outperformance	Relatively limited by cost reducing fixed price contracts	Less important - Seek predictability more than outperformance	Several, including fuel contracting, energy trading, operation, availability and efficiency improvement
Risk	Limited by contracts and may have little market exposure	Limited Often look for low risk opportunities to reduce market exposure	Moderate, including fuel price, dispatch, market demand, regulation
Return	Low due to lower risks	Low Willing to take lower expected returns in order to limit volatility	Moderate, equity type returns to manage risks and provide incentives for outperformance
Growth	Limited for project only investments	Limited Seek inflation protection, but not growth	Moderate, through natural fuel price inflation and performance and availability enhancement

Creating New Financing Models for Renewable Energy

Solutions begin with tailoring business models to the right set of investors

Every investor has a different set of priorities and constraints. Equity investors are willing to take more risk in order to achieve higher returns; debt investors trade higher returns for more secure cash flows. Some investors will need their money in six months' time, while others are investing for expected needs 20 years from now. The key to optimizing financing costs for any investment is to match the investment and the related regulatory and corporate structure with the investment pool that is most closely aligned with the financial characteristics of the investment in question. From this perspective, three sets of investors may be particularly well suited to invest in renewable energy:

Institutional investors seeking to match reasonably well-defined cash flow needs over a long period of time to service liabilities such as pensions and life insurance policies

Municipalities and other local and regional agencies seeking to provide long term infrastructure for themselves and their residents and companies

Energy users (and in particular, large consumers) seeking long term energy price certainty or a hedge against volatile energy costs

We discuss each type of investor in turn.

Institutional investors are a good match, but barriers limit potential

In many ways, institutional investors, such as insurance companies and pension funds, would be the natural owners of renewable energy projects. Once development and construction risks have passed and long term contracts or reliable feed-in tariffs are in place, renewable energy projects can deliver the long term, steady returns that institutional investors seek. Table 1 compares institutional investor requirements and typical utility requirements against the characteristics of renewable energy projects.

A CPI report released in 2013 examined the potential for institutional investment in renewable energy.[2] We found that the match is good, and that project level investments in renewable energy would be very attractive to institutions, but that there are a number of constraints that limit institutional investment in projects. Our analysis indicated that even if 1) policy was perfectly aligned and 2) every institution availed itself of the renewable energy project opportunity to the maximum level within its risk and strategy parameters, institutions could only provide 24% of project equity and 49% of project debt. These levels would not provide enough competitive pressure to lower returns, and therefore renewable energy costs, to the lowest level possible. **On the other hand, on their own, institutions can meet more than twice the equity and 139% of the debt requirement for renewable energy, if it is structured as in corporate finance instruments, such as stocks or bonds.**

Figure 3 shows how the various constraints on direct investment in renewable energy projects shrink the pool of available capital.

The main barriers to institutions investing directly into projects include:

Size of the institution – Investing directly in projects requires building skills and presence and hiring a team to source and complete the transactions. Unless this team creates value through a sizeable number of large transactions, the additional value achieved will not justify the cost of the team and the transaction costs. We found that only 150 or so institutions worldwide would be large enough to justify the costs compared to the value that could be provided from a direct project investment portfolio.

Liquidity – Project investments, like real estate or other real assets, are less liquid than stocks of bonds; that is, they are more difficult and expensive to sell if an unexpected need arises. This illiquidity creates a risk to institutions that require regulators and investment officers to limit the amount of illiquid investment in a

[2] Climate Policy Initiative. 2013. *The Challenge of Institutional Investment in Renewable Energy.*

portfolio and to offset illiquid investments with other extremely liquid, but lower return, investments such as government bonds.

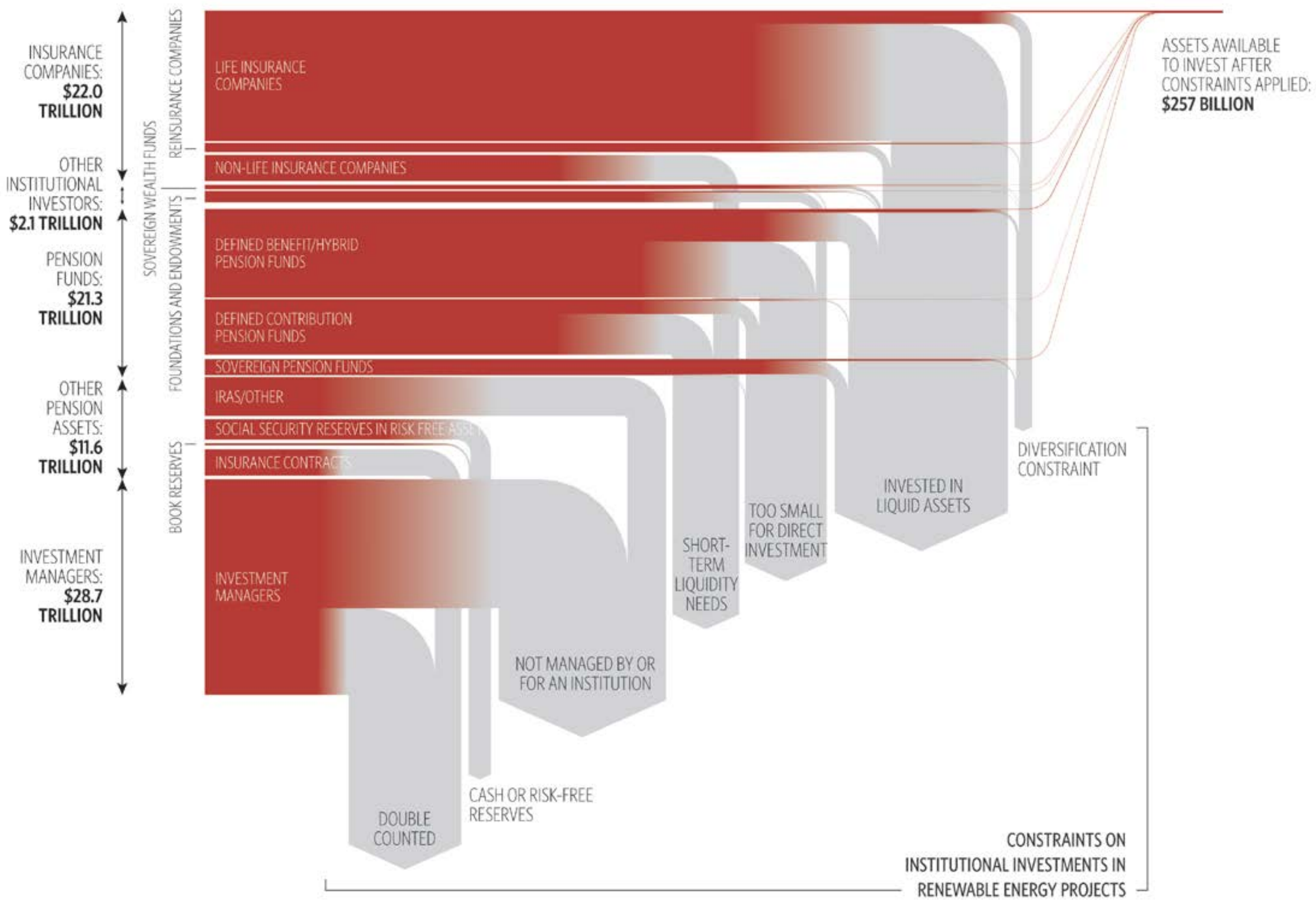
Diversification – Institutions must diversify their portfolios to manage risks.

However, these constraints are much less important for investments in corporate equity or bonds. For these types of investments, stock markets provide liquidity, analyst research is available to reduce the resources required to evaluate an investment, and transaction costs are much smaller. The difficulty in overcoming these constraints explains the persistence of publicly traded IOU financing structures despite their disadvantages. The key to financing renewable energy efficiently is to develop structures that marry the advantages of corporate investments, including their transparency and direct access, with the cash flow profile of project investments.

New corporate structures such as investment trusts and "Yield Cos" could bridge the gap and provide both liquidity and direct access to cash flows

There are investment structures that provide

Figure 3: This diagram depicts the potential flow of institutional investment into renewable energy project debt and equity. Only a very small fraction of the $70 trillion of assets managed by institutions could make their way into renewable energy projects. (Source: CPI, *The Challenge of Institutional Investment in Renewable Energy*, 2013)



liquidity, more direct access to cash flows and can be quoted and traded on an exchange. Real estate investment trusts (REITs), infrastructure funds, and Master Limited Partnerships (MLPs) are prominent examples where illiquid assets are bundled together in corporate structures with steady cash flows in the form of dividends, and then traded in liquid markets. More recently, renewable energy and other infrastructure-type assets have been bundled into "YieldCo" structures that are traded on exchanges mainly to investors seeking steady dividend yields based on real underlying assets. NRG Yield, Greencoat Energy, Pattern Energy, and the recently announced Nextera YieldCo are all prominent examples.

While developing these first YieldCos is an important first step, current YieldCo designs only move part of the way towards a structure that would optimize renewable energy finance and lower its cost. To minimize the effective average lifetime cost of energy from a project including both operating costs and required investment returns (also called the levelized cost of energy, or LCOE), the new type of YieldCo investment class must do the following.

1. PROVIDE HIGHLY PREDICTABLE LONG TERM CASH FLOWS

The YieldCo:

Must pay out nearly all of the free cash it generates from the underlying projects to the YieldCo owners. Current YieldCo or MLP designs retain 10-20% of cash to use for investment in future projects. This retention and potential investment creates uncertainty and risk for investors. The investor cannot rely on predictable cash flows to meet liabilities, but instead will have uncertainty about whether the YieldCo or MLP management will make bad investments. To compensate for the risk, the investor will demand either a growth premium or an equity premium for the investment that will ultimately increase the cost of finance for renewable energy.

Should be backed by long term contracts or feed-in tariffs that provide clear sight of future cash streams. Previous CPI analysis found that increasing the duration of contracts was the most effective policy tool for reducing the financing costs of renewable energy.[3]

Should own a diversified set of projects. Owning diversified assets will reduce the risk associated with uncertainty around individual projects.

Should invest in assets that are in operation or with iron-clad guarantees to reduce construction and development risk. Fixed operations and maintenance contracts can further enhance the attractiveness.

2. PROVIDE LIQUIDITY IN THE INVESTMENT

The YieldCo:

Should be exchange-traded or otherwise provide frequent transactions and pricing information. This information and the relatively low transaction costs will reduce the illiquidity penalty and also enable smaller institutions to invest.

Should be large enough to attract a large set of investors, as well as research and financial sector analysis. There needs to be enough interest in the security that

[3] Climate Policy Initiative. 2011. *The Impacts of Policy on the Financing of Renewable Projects: A Case Study Analysis.*

brokerage firms will cover the company and provide recommendations. This research will enable smaller institutions with smaller investment teams to make decisions about whether or not to invest.

3. PROVIDE INVESTMENT AT LOW FEES

The YieldCo must have a light management structure and low overhead costs lest these costs consume the advantage that the YieldCo structure provides. One of the major problems that institutional investors cited — beyond the management risks of buying and selling assets — was the high fees that eroded the investment case. With the benefit driven by the 2% per year or so difference between corporate bond and project bond financing costs, these fees would need to be significantly lower than current funds.[4]

With lower churn and less emphasis on long term portfolio management, fees may be structured as an upfront cost rather than an annual cost.

4. BECOME ESTABLISHED AS PART OF THE PORTFOLIO OF OPTIONS FOR INSTITUTIONAL INVESTORS

Institutional investor strategists and asset allocators use historical financial performance data. The YieldCo asset class will need to establish itself as a distinct asset class with unique characteristics so that institutions can incorporate these characteristics into their asset allocation and risk models.

What needs to be done?

Institutional investors and YieldCos

- Develop new YieldCo securities and establish YieldCos as an investment class
- Fine-tune renewable energy regulation to meet financial requirements
- Work with institutional investors and financial regulators to incorporate this new asset class within their portfolios and asset-liability matching (ALM) strategies and analysis
- Develop a model for passing on savings to lower energy costs — potentially by revisiting development fee structures, construction risk costs, and business model

[4] Some MLPs suffer from similarly high overhead costs if they make use of management incentives known as incentive distribution rights (IDRs). IDRs allocate an increasing fraction of free cash to the general partner with increasing cash payouts, providing an incentive for growth. Thus, while the limited partner yield may appear to be low, the cost of equity is actually much higher when general partner IDRs are considered.

Current YieldCo designs are beginning to establish the asset class, but their design fails to reach its full potential for reducing financing costs

The first set of YieldCos that have emerged recognize the opportunity to segregate low risk assets into liquid securities that investors can easily access. Unfortunately, while these YieldCos establish the concept, their design does not fully take advantage of their potential to reduce financing costs for new renewable energy projects. Comparing existing YieldCos with the optimal features mentioned previously, we note a few key differences:

1. **Many YieldCos have been designed with built-in expectations for growth.**[1] Some profits are being retained instead of being fully distributed as dividends, in order to buy more assets. There may also be expectations that the company will issue equity to further grow its assets, diluting current investments and creating uncertainty. The result is that while yields are currently low, the implied growth premium actually implies higher returns to compensate for the re-investment risk. Thus, these are structured closer to equity vehicles than would be optimal to minimize financing costs.
2. **High costs and fees.** In order to pursue growth, current YieldCos need a more sophisticated and expensive management team in place, increasing costs.
3. **YieldCos, like NRG Yield, have been built up using existing assets.** The result is that the financial gains due to the lower financing costs coming from better transparency and access to the project cash flows will not lower the price of renewable energy since the price will generally have been set when the original investment decision was made. Only when developers have the certainty that lower financing costs will be realized can they reflect the lower costs in project bids or prices. Without that certainty, prudent investment practice dictates that they do not consider future potential benefits to project economics in case they do not materialize. Under these circumstances, the value that comes from creating a YieldCo will flow back to the company, but not to the consumer or to lower electricity prices. Only when developers have enough confidence — and potentially pre-contract arrangements — will YieldCo development lead to lower energy costs.

This choice has often been made in the U.S. due to tax considerations as a large fraction of the benefits of many U.S. renewable projects are provided through tax credits or deductions. The YieldCo must have enough assets generating net tax liabilities to offset those credits and deductions. This requires them, primarily, to hold older plants that have long since used up their accelerated depreciation benefits and tax credits.

Municipal governments could invest to provide renewable energy as part of local infrastructure needs

In many ways, renewable energy looks more like an infrastructure investment than conventional generation. Renewable energy is much more competitive when it is fully financed at low interest rates (with a developer premium paid separately rather than through the energy price) and can offer fixed long term energy prices. Municipalities have both low borrowing costs and a long history of financing infrastructure for municipal needs, giving them the ability to finance renewable energy at low costs and lock in prices for residents. This arrangement may be attractive in many areas in the U.S. and Europe.

Unlike institutional investors, municipalities could invest directly in renewable energy projects without the liquidity concerns, much as they invest in infrastructure. Municipalities can use the energy generated to offset their own needs or to provide clean energy options to their residents and companies.

There may also be a need to aggregate municipal finance through provincial or national infrastructure banks, enabling smaller municipalities to access capital markets cost-effectively.

What needs to be done?

Municipal Finance

- Municipalities to recognize the value of providing long term fixed-price energy services
- Regulation to facilitate the provision of electricity by municipalities to meet their own needs and those of their residents
- Potential help from state or national governments to launch bond issuances
- Develop Renewable Energy Operating and Service Companies and contracts

Crowdsourcing and direct investment could help consumers and industries fix their energy costs for the long term

The growing popularity of rooftop solar installations partly reflects environmental consciousness, but it also reflects a desire among many consumers, large and small, to fix their price of electricity for a longer term, at a lower price. However, many consumers do not own a roof that makes sense for rooftop solar and are thus blocked out of securing long term, low cost energy prices. Small commercial and larger utility scale renewable energy projects, financed through electricity consumers in exchange for fixed long term, low cost energy, could meet this pent-up demand, possibly at a lower cost than some rooftop installations. To make this work, regulation would need to allow consumers to use the same net metering arrangement often in place for rooftop solar: Consumers could offset their own usage with energy produced by these projects, with an adjustment for time of day.

Additionally, net zero building standards could provide further impetus if external renewable supply sources could be bundled with a building upon sale and attributed to the building's net zero energy performance. In the analysis that follows, we do not specifically evaluate the financial value of this option, as consumer preferences and capital availability vary tremendously. We only highlight this as an additional option that could, with an appropriate business model and industry regulation, contribute to lower-cost renewable finance. This model could comfortably sit beside the institutional investor-driven YieldCo finance model and the municipally financed infrastructure model. Indeed, municipalities might offer some long term renewable energy supply contracts to residents that compete against crowdsourced options.

What needs to be done?

Crowdsourcing

- Regulation to allow offsetting renewable energy purchases from metered usage
- Building regulations could accelerate this market by allowing offsets from outsourced renewable energy provision (potentially as part of net zero energy building standards)
- Creating business models and outsourcing platforms

We note that all of these options have appeared in one form or another in various places, but accelerating and facilitating their deployment could be an important step to a new electricity industry business model. We also note that commercial and industrial consumers, such as Walmart, are already significant investors in renewable energy with great potential to grow. Furthermore, their electricity demand profile resembles a daily solar production curve, helping alleviate some of the complications with fluctuations in renewable energy production.

These financing structures and business models could reduce the cost of renewable energy by 20%

The models discussed above provide consumers a choice in how they pay for electricity. They will also reduce renewable energy finance costs by matching its investment characteristics with investors seeking similar return profiles.

The analysis that follows is based on the CPI renewable energy project finance model and has been the basis of other CPI reports, including the 2011 report "The Impact of Policy on the Financing of Renewables – A Case Study Analysis," which explains the model in more detail. In summary, this model evaluates the cost of debt and equity in a project and how the financial structure and cash flows would vary over time as a function of policy, set against the investment requirements of potential equity providers, lenders, bondholders, and other investors. All inputs and assumptions are available in Appendix I of this document.

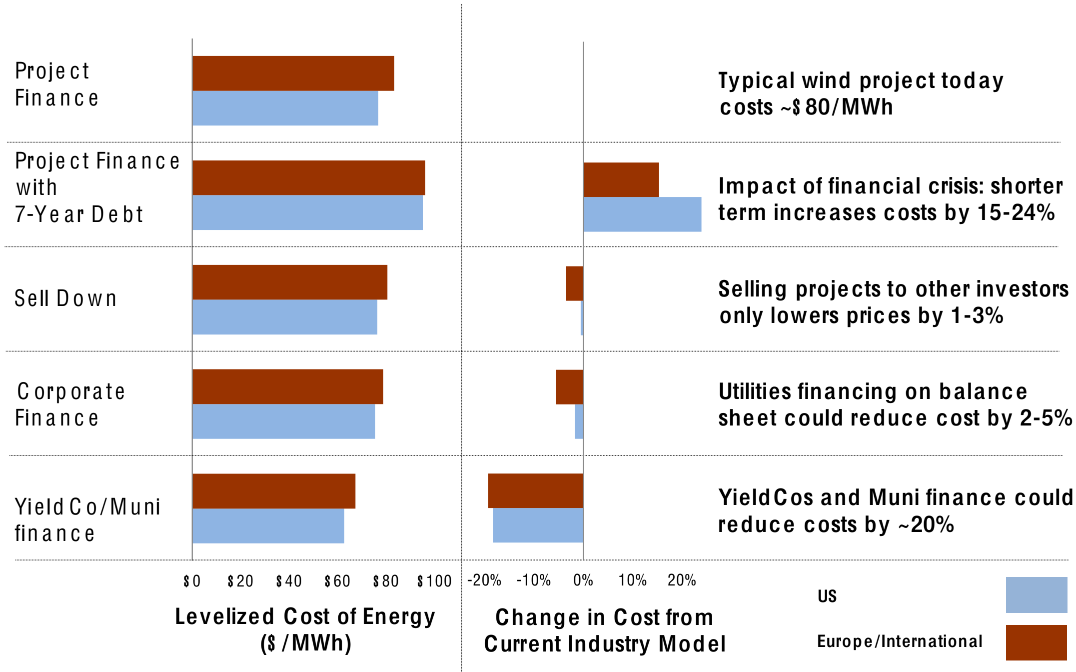


Figure 4: New business models could reduce the cost of financing a typical wind energy project by 20%

The first bar in Figure 4 shows a typical wind project that is project financed under accounting treatment in the U.S. and Europe, without any tax credits. The model suggests that a price of around $80/MWh would be required to make project returns acceptable to equity and debt investors alike. The cost in the U.S. is slightly lower, mainly due to how depreciation is treated for tax purposes.

Our 2011 report stressed the importance of longer term policy support in order to facilitate longer term debt as a mechanism to lower the levelized cost of energy (LCOE). However, the financial crisis has increased the cost of offering longer tenor (duration) debt. To illustrate the potential impact of this, we modeled the same project, but assuming that debt tenors were reduced to seven years. The impact could be to raise the LCOE of renewable projects by 15-24%.

The next scenario is for projects to be sold down. In a competitive environment, IOUs and IPPs have reacted to increasing competition by exploring new business models. One involves selling most of the project to investors — including institutions — soon after the plant begins operating. In this manner they can enhance returns to their equity. This strategy has only a limited impact on costs and, as we will explain in Section 2.3, can be employed only to a limited extent due to its impact on the volatility of the sponsoring company's finances.

The fourth alternative would be for an IOU, with relatively low capital costs, to use its own balance sheet for financing the project. In the more developed, stable, and competitive markets, such as onshore wind, many companies are financing projects on their balance sheets or as regulated return investments. Our model suggests that doing so reduces LCOE by 2-5%, but further reductions are limited by the return requirements of IOUs. (In the next section, we will analyze why this occurs.)

Applying appropriately structured YieldCo or municipal finance models to projects — in a way that the lower financing costs can be relied upon and included in the investment decision of the developer — could reduce the LCOE of renewable energy projects. Figure 2 shows that a YieldCo model could reduce LCOE by almost 20% compared to existing project finance models.

The Problems with Utility Based Renewable Finance

Current electricity supply industry structures increase the cost of financing clean energy and clean energy infrastructure

Publicly traded companies such as IOUs and IPPs currently act as project developers for many generation projects and enjoy natural advantages, such as the ability to obtain project debt at a low cost. However, the mismatch between the demands of utility investors and the financial characteristics of renewable energy projects prohibits IOUs from acting as developers for renewable energy generation projects at a large scale. In addition, when utilities do act as project developers, they require a premium to reach their return on equity hurdle for investors, which increases the financing cost of renewable energy. In this section of the paper, we explain the reasons and implications of this mismatch.

Shareholders expect equity returns from investor-owned utilities

IOU shareholders generally consider utility investments lower risk and therefore lower return than many other equity investments. Nevertheless, these are equity investments in which shareholders expect higher returns than bonds, and some revenue growth, in exchange for assuming some risk. While there can be a large difference between purely regulated utilities and those that have some exposure to markets, most IOU shareholders are more focused on stable, growing dividends than they would be for many other investments.

Utilities are priced as businesses rather than projects, where a significant amount of the value is in the ability of the business to create new investment opportunities and opportunities for outperformance. The end result is that the typical return on equity (ROE) for IOUs in the United States is currently around 8%,[5] while the 20 year corporate bond rate is close to 5%. The 8% ROE would serve as a minimum rate for the equity returns of a typical investment by an IOU, but companies often build in a buffer, as an 8% return would provide no incremental value to the company (that is, the company would get 8% from a project, but pay 8% to its investors, so the company would not grow and would have no buffer if returns were lower than expected). Furthermore, the ROE for unregulated assets is typically higher, so an IOU may require a minimum ROE of 12% for a generation project.

Going back to Table 1, we can compare the characteristics of an individual, standalone renewable energy project with the expectations of IOU investors. The figure shows an obvious mismatch, where the risk and cash flow profile of a renewable energy project (with a fixed-price energy contract or feed-in tariff) justify lower returns than what IOU investors seek.

A premium is required for renewable energy project returns to attract investment from utilities

Providing a project level return of 12% would make renewable energy, or indeed most generation projects, very expensive. Regulation and market forces assume that

[5] Based on weighted average equity costs for top 10 U.S. IOUs in 2013. Data from Bloomberg.

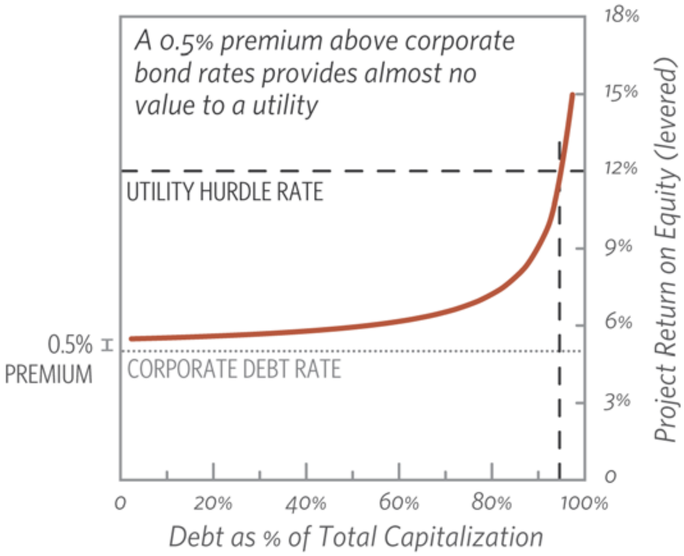


Figure 5: Equity returns with a 0.5% premium over bonds

one of several strategies can be employed to reach the ROE requirements while lowering the overall costs of the project. The most important of these is leverage, where a developer borrows against the project to concentrate both risks and returns on the equity.

Meeting the ROE hurdle through increased project leverage

IOUs enhance equity returns through increased leverage — that is, by borrowing against the asset, thus effectively reducing the amount invested by the amount borrowed, while retaining both the risks and some of the higher return. Increased leverage might allow the IOU to concentrate the financial upside, and the risks, into a more concentrated equity investment. For example, with 75% debt in a project, the equity premium over debt costs to the project becomes four times higher as the equity return — and risk — is concentrated into one-fourth of the investment.

For leverage to work, an investment must have some premium over the cost of debt. Figure 5 shows the hypothetical case where a project has an overall return that is 0.5% above the 5% cost of debt. The top line shows what the effective return on equity (in percent per annum) would be as leverage increases. With no debt, in this hypothetical case the equity investor would get a 5.5% return. By borrowing 50% of the investment cost, the equity investor could raise their return to 6% (but the effective investment is now only half the size).

Increasing debt further increases the return to the equity holder, but in this case the project would need well over 90% debt to reach equity returns that would be attractive and fit within hurdle rate expectations. The problem is that as debt increases, the size of the equity investment falls. At over 90% leverage, the equity investment now becomes one-tenth the original size, possibly too small for the IOU to invest the time and management resources required. More importantly, lenders use different metrics to value a project and would be extremely unlikely to lend over 90% of a project.

Meeting the ROE hurdle through increased balance sheet leverage

A second strategy is for utilities to use their own balance sheets, raising debt against all of their assets rather than just those of the particular project. However, IOUs typically use standalone project financing metrics to determine how much debt should be attributed to projects and to calculate the effective return of the project to the utility. Using project financing metrics imposes financial discipline on the utility and ensures that the utility is not effectively cross-subsidizing individual projects or using disproportionate shares of the company's debt or risk management capacity. Thus, as in Figure 6, to make a project attractive to a utility company while maintaining reasonable leverage ratios of between 60% and 70%, the overall project return would need to rise to 7.5%, or a 2.5% premium over corporate debt costs.

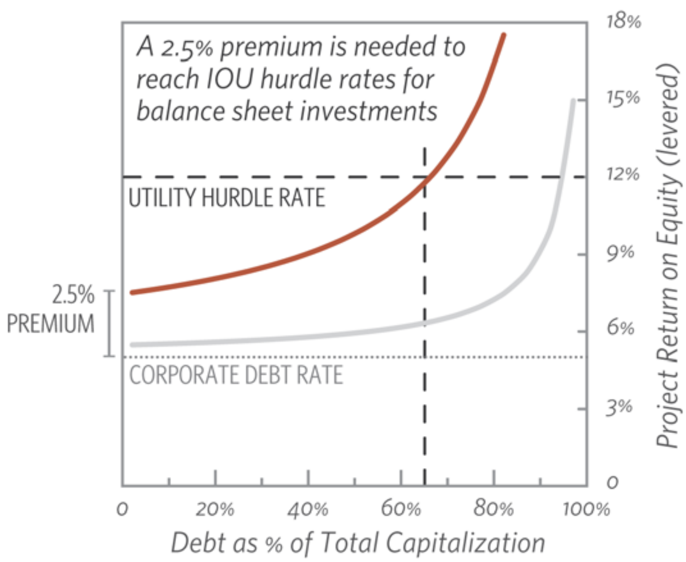


Figure 6: Equity returns with a 2.5% premium

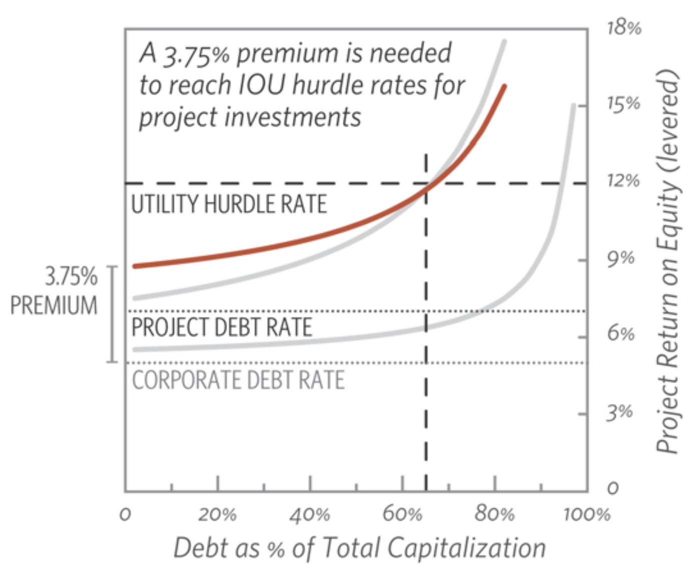


Figure 7: Equity returns with a 3.75% premium

While 60 to 70% leverage is typical for project financing, utilities tend to have lower leverage ratios for their overall balance sheets. According to the Edison Electric Institute, as of 2013, debt represented 56.7% of total capital for the average U.S. investor-owned utility.[6] Borrowing at higher rates can increase the default risk and therefore increase the yield, or cost of the debt. There are two ways to address this, either lowering the share of debt, which increases average financing costs, or through standalone project financing. While corporate debt currently yields slightly below 5%, project debt can yield 2% more, or close to 7%. Increasing the cost of debt reduces the value of additional leverage, as it is the premium over debt that is levered to increase equity returns.

Figure 7 goes that next step. For the hypothetical project-financed wind farm with 7% debt, a premium of 3.75% over corporate debt is required to make the project reach utility equity return hurdles and, therefore, be attractive to utilities and their investors.

An important strategy for enhancing the value of renewable energy portfolios is of limited use to IOUs

[6] Edison Electric Institute. 2014. *2013 Financial Review.*

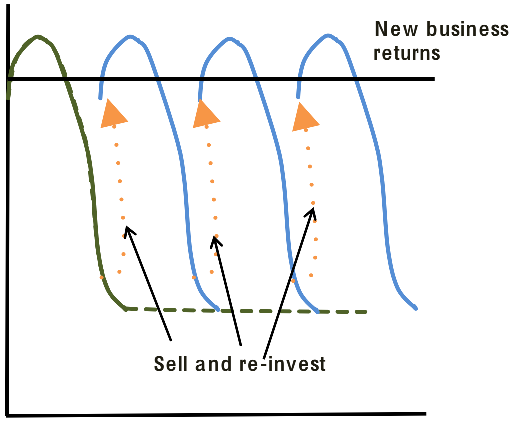


Figure 9: Buy, build, and sell strategy enhances returns

As we demonstrated in the previous section, matching the return requirements of IOUs and other developers increases costs substantially, even with a significant use of leverage. A further strategy that developers and utilities have used has been to optimize the returns of the renewable energy portfolio rather than just of the project itself.

This strategy works because projects go through distinct phases, where there are different risk and return profiles. Early in a project life, the risks are high, so an investor looking to buy all or part of the project will require a very high return to cover those risks. As a result, the price that that investor would offer would be correspondingly low (a higher return requirement translates directly to a lower offer price).

As development, construction, and commissioning proceed, doubts about whether the project will go ahead fade, potential delays or cost overruns either materialize or go away, and risks generally decline. With this greater certainty, the outside investor can feel confident enough to offer more for a project. The returns — and crucially the returns to the project developer — for holding onto the project for the rest of its life begin to fall. By the time the project is complete and operating, very few risks remain for the investor so long as the right contracts and policy are in place. At this point, the developer/utility can sell all or a part of the project at a relatively high price. Figure 9 depicts the evolution of returns for an investor paying the market price and holding for the project life against the amount of capital invested at any given point in a project's life.

With this pattern in mind, developers have learned to sell projects once risks have fallen to investors seeking predictable, long term cash flows. By developing, building, commissioning, and selling the projects, developers can enjoy the high risk/high return part of the investment cycle; by re-investing the proceeds of a project into a new project, the developer can create a business with higher overall returns (See Figure 8).

Utilities, in their role as project developers, have also followed this model to enhance returns. However, there are limits to utilities operating in this fashion. Namely, while returns under the buy, build, and sell model may be attractive, the timing of those returns and the cash flow profile is not. Figure 10 shows why this is the case. As previously discussed, utility investors hold

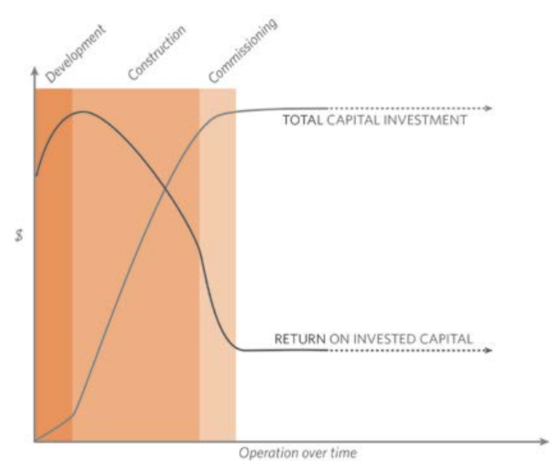


Figure 8: Capital invested and project returns over a typical renewable project lifetime (stylized)

shares in expectation of relatively large, steady growing dividends. A cut in the dividend could lead to a utility's share price underperforming for several years. Even the threat of a dividend being cut (for instance, because earnings are insufficient to underpin the current dividend policy) can cause a utility to underperform.

A utility, therefore, needs to build a convincing stream of steady or slowly growing investments to underpin its dividend strategy. As in the left hand side of Figure 10, a typical utility will add a few longer term investments on a regular basis; each of these builds off of the existing businesses to provide a steady growth profile. The build and sell model takes these long term, steady profit streams and converts them to one larger profit lump in a single year. While the return on equity improves, the utility is left with a volatile earnings stream that will depend on how many deals the utility closes in any given year. In addition, when the economy is bad or projects are delayed, a utility may close no deals and be left with an earnings hole (for example, see the right side of Figure 10). The utility will have the choice of either maintaining a more conservative dividend policy or offering volatile dividends. Either way, investors in utilities will no longer see the utility as a safe revenue source and will demand higher returns (that is, the share price will fall). The utility will begin to look like riskier companies (for example, independent project developers or oil companies) and will need to raise the return on equity it requires for projects. **Thus, in order to maintain the financial characteristics that investors expect from utilities, the companies need to limit the extent to which they enhance returns through portfolio management.**

Notably, YieldCos with built-in growth expectations can follow the same fate, leading to higher-than-needed market return requirements and more expensive renewable energy projects.

Utilities lack the financial firepower needed to finance large scale investment and industry transformation

While the returns on renewable energy investments need to be higher than they might otherwise be to fit within the business and financial models of utilities, even with these enhanced returns, utilities may not have the financial firepower needed to

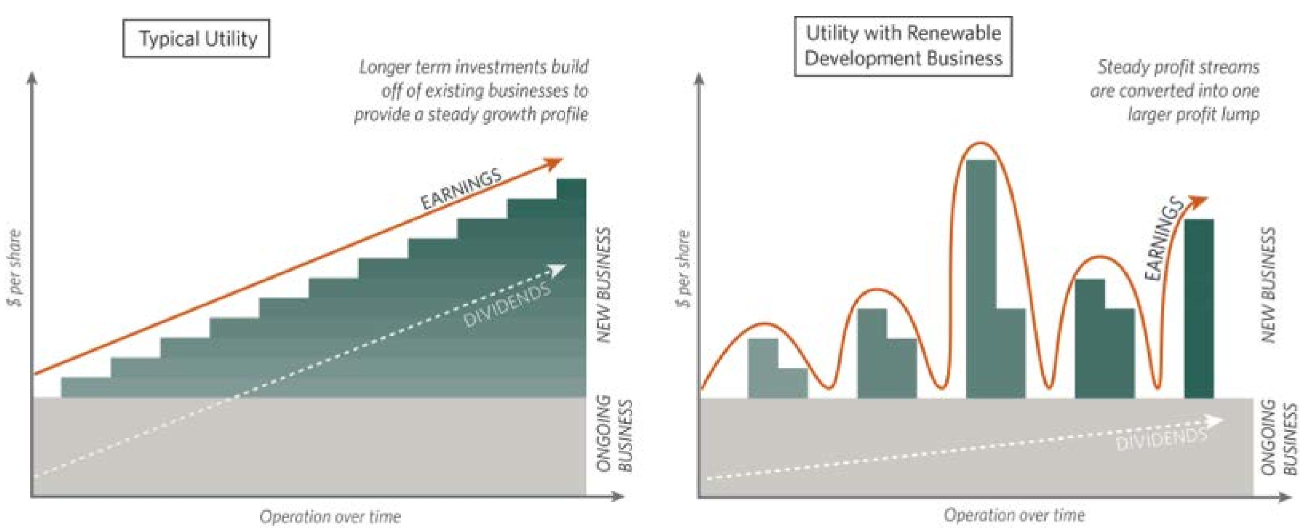


Figure 10: Growth profiles of a typical utility long term business model versus a build and sell model.

transform the electricity industry at scale.

As discussed in Part I of this series, all elements of the IOU business in the U.S. and Europe are under tremendous pressure. Utilities have falling revenues and, in many cases, earnings. As a result, many, particularly in Europe, find themselves with too much debt to be supported by their revenues. In response they need to sell businesses, reduce capital expenditures, or both.

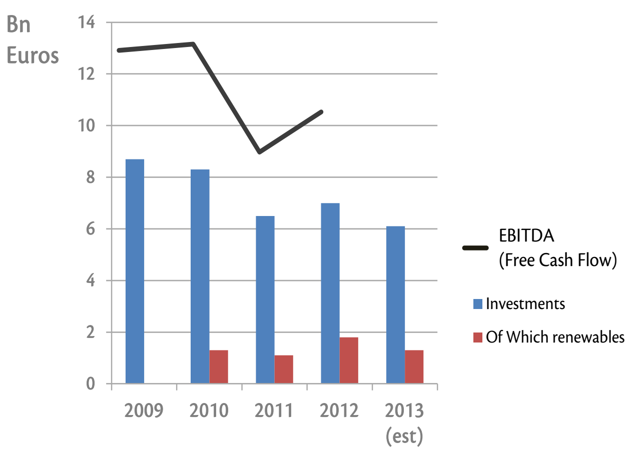


Figure 11: E.on's free cash flows are shrinking and with them its ability to invest

Figure 11 shows the recent financial history of E.on, a German utility. EBITDA — a measure of free cash flows from the business that are available to pay for new investment, dividends, interest payments, and taxes — has been declining since 2009 as a result of falling prices, low economic growth, plant closures, and business divestments. As a result, E.on has cut investment from over EUR 8 billion to around EUR 6 billion, short of its own forecasts. A significant portion of its investments are dedicated to maintenance of existing businesses rather than growth, thus growth-related investments have fallen further than the 30% represented here. While renewable investment has stayed relatively strong over this period, it now consumes a major portion of the growth investment budget of E.on, so there is little room to grow further. In response, E.on is reining in renewable investment and concentrating on fewer geographies.

Thus, not only are current utility business models ill-suited to finance renewable energy efficiently, in many cases IOUs do not have the financial firepower to increase their investment significantly.

Summary

The current investor-owned utility business model has served its purpose well in delivering scale to lower costs, integrating the industry from fuel supply to consumer, and enabling effective regulatory regimes in a world dominated by fossil fuel generation. However, renewable energy is a game changer for these companies and the industry. Its risks and rewards require different thinking and business models tailored to its specific characteristics.

New models for financing renewable energy are already beginning to emerge but we should not assume that these will necessarily be the best for allocating risk and encouraging investment at the right return levels. The industry needs creative thinking, careful design and a gentle regulatory, financial and structural push to reduce the costs of renewable energy. Policymakers can help accelerate this transition by working with investors, electricity companies, and financial regulators to enable the development of new financing vehicles, redefine markets, and build new institutional structures for a 21st century low carbon electricity system.

References

International Energy Agency. 2012. "Energy Technology Perspectives 2012: Pathways to a Clean Energy System."

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Appendix I: Inputs and assumptions to project finance model

	Base Project Finance	Base Project Finance Debt Constrained	Sell-Down	Utility Balance Sheet	YieldCo
Cost of debt	7 percent	7 percent	7 percent	5 percent	5 percent
Cost of long-term investor equity	8 percent	8 percent	10 percent	10 percent	8 percent
Cost of developer equity	12 percent	12 percent	12 percent	12 percent	12 percent
Leverage (% of debt)	US: 66.67% EUR: 73.93%	US: 51.47% EUR: 52.16%	US: 66.23% EUR: 70.76%	US: 49.51% EUR: 49.51%	US: 70.29% EUR: 77.19%
Terms of debt	Senior debt: 15 years Subordinate debt: 5 years	Senior debt: 7 years Subordinate debt: 5 years	Senior debt: 15 years Subordinate debt: 5 years	Senior debt 20 years Subordinate debt: 5 years	Senior debt 20 years Subordinate debt: 5 years
Developer premium	0%	0%	US: 7% EUR: 5%	US: 7% EUR: 5%	US: 7% EUR: 5%
All Scenarios					
DSCR	Senior debt: 1.40 Subordinate debt: 1.30				
Capital cost (before inflation)	During development: $201 million Construction: $1,471/kW				
P50-P90 capacity factor	P50: 24.87% P90: 22.54%				
Operational cost	Annual cost: $3 million in first year with 2 percent escalation O&M: $18.69/kW per year				
Tax assumptions	US Federal tax rate: 35 percent State tax rate: 5 percent Production tax credit (PTC): $0.0035/kWh Depreciation: 90 percent of eligible costs are treated with 5 year MACRS			EUR Federal tax rate: 20 percent State tax rate: 0 percent Depreciation: 15-year straight-line	

Assumptions used in calculating LCOE values used in Figure 4