THE CHALLENGE OF FINANCING UTILITY-SCALE LOW CARBON ENERGY PROJECTS

Overview

The financial and operational characteristics of large scale renewable energy are different from conventional fossil fuel generation. Renewable energy cash flows are dominated by initial capital investment, followed by a steady and predictable stream of cash inflows from energy sales. From a financier's perspective, the large initial investment followed by a reliable and steady set of payments looks more like a bond than an equity investment. This is substantially different from conventional power plants, which require comparatively lower capital investments but carry substantial operational risk due to fuel prices, operational expenditures, and the dispatching of electricity. Using a standard power plant financing model for renewable energy projects adds as much as 20% to the cost of renewable electricity.[i]

Financial Picture
Investment Value
Global investment in renewable energy was $244 billion in 2012:
U.S.: Approx. $36 bn
EU: Approx. $80 bn
Investments by Investor Type
$102 bn – Project developers
$33 bn – Households
$21 bn – Commercial/Financial institutions

New financing models that reflect the underlying financial characteristics of low carbon energy projects, as well as the investment objectives of relevant investors such as pension funds and insurance companies, can reduce the cost of renewable energy by up to 20%. However, policymakers will need to create the necessary conditions and overcome key constraints that have kept the institutional investors on the sidelines:

- **Investment practices** – Many pension funds will not invest directly in illiquid assets while others have not built the investment expertise required to invest directly in renewable energy.
- **Policy uncertainty** – Inconsistent policies like retroactive tariff cuts in Spain and start-stop incentives in the U.S. create an aura of uncertainty that keep institutional investors on the sidelines.
- **Policies that discourage institutional investors** – For example, the use of tax credits as an incentive mechanism in the U.S. discourages tax exempt investors, such as pension funds.

Current state

Deploying new types of financing models for renewable energy that better match its operational characteristics and investor profiles can significantly decrease renewable energy costs. Previous work by CPI has identified new financing models that have the potential to meet institutional investor needs and open up significant new pools of funds[ii]:

- **YieldCo** – Listed corporations designed to provide steady, long term dividends. These dividends are typically supported by ownership of a series of long term assets such as infrastructure and renewable energy. One example is NRG Yield, which owns 1.3 GW of natural gas, wind, and solar generation assets in the U.S. The assets all have long-term contracts to sell electricity. Pattern Energy is another company employing the YieldCo model with 1.3 GW of wind power projects in the U.S., Canada, and Chile.
- **Muni Finance** – Municipalities with borrowing capability can fund renewable energy projects entirely through muni level debt, with contracts arranged to manage and operate renewable energy projects. For example, in the U.S., Property Assessed Clean Energy (PACE) programs use the borrowing power of municipalities to provide low-cost renewable energy and energy efficiency loans for buildings that are paid through property taxes.
- **Industry/Individual Finance** – Part ownership of renewable energy projects by industries or individuals can be structured to provide up to 10-20 years of energy supply at a fixed price. For example, in Mexico, Walmart is already buying 17% of its electricity through power purchase agreements on wind projects.
- **Master Limited Partnerships (MLP)** - The assets in an MLP are effectively owned directly by investors but otherwise look like YieldCos and can be listed vehicles. MLPs provide tax benefits as they eliminate the corporate level of taxation. Current U.S. law does not allow MLPs to devote more than 10% of their portfolio of assets to renewables and retain their favorable tax treatment.

Questions for Analysis

This topic is central to CPI's work and follows on from specific projects CPI has conducted on the impact of policy on renewable energy and on the attractiveness of renewable energy investments — as currently structured — to institutional investors. Possible areas of further research include:

1. How should these financing models best be structured? What sort of secondary requirements, like legal frameworks and institutional learning, are needed for these models to function?
2. What is the potential impact of these financing models on the deployment of renewable energy around the world?
3. How will new business models for large scale low carbon energy catalyze reform and the development of new business models across the entire electricity supply industry?

[i] CPI. (Forthcoming 2014). Current Industry Business Models Constrain Low-Cost, Large-Scale Investment in Renewable Energy.
[ii] CPI (2013). *The Challenge of Institutional Investment in Renewable Energy*.

Overview

Transmission grids connect power plants across a region to cities and load centers. A well-functioning grid allows an electricity system to pool resources, reducing costs by accessing the least expensive resources and increasing reliability. An independent grid facilitates greater competition in generation and can thus lead to further efficiencies. Crucially, in a world where more of the output from generators like wind or solar plants is dependent upon weather rather than operator decisions, a grid can help balance loads from one region with favorable generating conditions to one with less favorable conditions.

Today's transmission infrastructure grew out of an era where utilities were more local. Transmission was optimized within the service area of a utility and gradually grew to interconnect these areas and achieve some of the benefits of larger-scale transmission. However, the ownership of transmission assets stayed local. Control and regulation have stayed at the state level in the U.S. and the national level in the EU. This is a barrier to achieving the benefits from wider integration.

Slowly, U.S. and European authorities have pushed towards integration but they have faced resistance. As a result, transmission bottlenecks prevent the cheapest and cleanest power from reaching load centers, and the potential for demand management resources to stabilize energy usage is limited.

Transmission System Overview

Asset Value

U.S.: Approx. $124 billion

EU: Approx. €600 billion for both transmission and distribution

Ownership/Operation Structure

U.S.: 243 transmission owners, some assets of which are operated by one of 7 Independent System Operators (ISOs)/ Regional Transmission Organizations (RTOs)

- 3 operating interconnection regions (West, East and Texas)
- Regulated at state level and federal level (for interstate flows)

EU: 41 Transmission Service Operators (TSOs) in 34 countries

- 3 operating interconnection regions (Nord Pool, UCTE and Great Britain)

Key Players

U.S.: ITC (14% of U.S. grid); investor-owned utilities; federal and muni utilities; ISOs/RTOs; state regulators; FERC (federal regulator)

Europe: National Transmission Companies including National Grid (UK); Re Electrica (Spain); Terna (Italy); REN (France) and others; EU and Member State regulators; UCTE; Nord Pool; European Network of Transmission System Operators for Electricity (ENTSO-E)

As countries look to grow renewable energy and demand-side resources as part of the generation mix, having a large, regionally integrated grid managed independently from generation and distribution assets will be increasingly important to ensure system stability and lower energy costs.

Current state

1. The U.S. Federal Electricity Regulatory Commission (FERC) has nurtured open, regionally focused transmission markets through Orders 888, 889, and 2000, which introduced the independent system operator (ISO) model and laid out the requirements for Regional Transmission Organizations (RTOs).
2. The European Commission's Regulation EC 714/2009 mandated increased cooperation and coordination among transmission system operators and the creation of a central body (ENTSO) to play an increasingly larger role in planning and control of the transmission system. It also mandated increased investment in network interconnections and other improvements to improve access to transmission networks across borders.
3. Transmission-only companies have developed across Europe and the U.S., with many now publicly traded.
4. Nevertheless, the level of integration and independence is uneven across both the U.S. and Europe. Progress has been slowed by the vested interests of political and corporate players.

Questions for analysis

1. How will wider integration and greater independence for transmission companies reduce the cost of integrating low carbon energy into the system?
2. What are the key management, regulatory, policy, finance, and investment issues that will facilitate the development of the grid in a manner consistent with a low carbon energy system?
3. How will these new transmission companies be financed and organized, and will that affect low carbon energy finance?
4. What impact will separating transmission assets from generation and distribution have on the business models and capabilities of existing incumbent players such as utilities?

UPDATING ELECTRICITY MARKETS AND ENERGY BALANCING SYSTEMS TO PROMOTE EFFICIENT INVESTMENT IN GRID FLEXIBILITY

Overview

The flexibility provided by fossil-fueled and hydro generation is a cornerstone of modern electricity systems. With each plant offering flexibility to adjust output and other operating characteristics in accordance with system needs, operators have been able to choose among a number of generation sources, each with different cost, location, and operating characteristics. Operators have sought to minimize costs by selecting the lowest cost power plants within reliability and transmission constraints. For their part, electricity consumers have had little incentive to participate in system operation and so grew accustomed to electricity being available on demand. In turn, demand became increasingly variable, fluctuating with the time of day, weather conditions or even major sporting events. Operators built extra power plants to meet the peaks of this variable demand and relied upon flexible but expensive plants to adapt to its uncertainty.

Grid flexibility can be increased without investing in new power plants. One solution is to expand balancing areas by integrating electricity markets and building new transmission infrastructure. Plants in one region that are not being used can be dispatched to manage demand in another and vice versa. Updating market designs is another solution. For example, shortening the dispatch intervals of power plants can help increase the accuracy of plant dispatching and decrease the need for costly regulation services.

Another approach is to use demand-side flexibility. Over the last few decades, demand response — where customers are incentivized to participate in the market and offer flexibility in demand — has become an important part of managing the system. At the same time, authorities have sought to introduce competition and improve the economics of using both the generation and demand response resources by creating markets for

<u>Balancing System Overview</u>

Ownership/Operation Structure

U.S.: 103 balancing authorities

EU: 41 Transmission System Operators (TSOs) perform balancing functions

Key Players

U.S.: ISOs/RTOs (including PJM, NYISO, ISO-NE, MISO, ERCOT, CAISO, SPP); Federal balancing authorities (BPA, WAPA, TVA); regulated utilities (Southern Company, Pacificorp, etc.); municipal utilities (Los Angeles District Water and Power; Seattle City Light, etc.), FERC

EU: ENTSO-E; Agency for Cooperation of Energy Regulators (ACER); TSOs (TransnetBW (Germany),TenneT NL (Netherlands), National Grid (UK), Scottish Power Transmission (UK), RTE (France), Fingrid (Finland), Statnet (Norway), APG (Austria), Elia (Belgium), REN (Portugal), etc.)

electricity and developing ever more sophisticated systems for paying to pay for transmission and reliability services.

As electricity systems increasingly shift towards low carbon energy sources that have effectively zero marginal cost, but offer little flexibility, the role of existing flexible generation and the balancing markets that schedule generation from these plants will change enormously. The value of energy from fossil-fuel plants will fall dramatically, particularly when faced with a carbon constraint, but the value of the flexibility, response, and security services these plants offer will increase just as dramatically.

Current state

A number of studies have estimated the potential benefits of expanding balancing areas and updating market designs and operational characteristics. For example:

- In the U.S., PJM Interconnection operates a single electricity market across 13 states and the District of Columbia. It is currently the world's largest market and represents 830 companies, 60 million customers, and 167 GW of capacity. PJM generates as much as $2.2 billion in annual savings by improving reliability planning, optimizing generation investment, reducing energy production costs and optimizing additional grid services like voltage control.[i]
- After taking control of Entergy's transmission network, Midwest ISO estimates annual benefit to member utilities of $1.2 billion annually from lowered system operating costs and shared reserves in an expanded energy market; Entergy estimates cost savings for customers of $140 million annually.[ii]
- NREL studied the benefits of sharing reserves and moving to a 10-minute dispatch interval throughout the U.S. Western Interconnection. They estimated that cost savings as high as $1.46 billion per year could be realized as a result of the shift.[iii]
- In the EU, annual benefit achieved by implementing a regional balancing market where such a market is not in place is estimated at €221 million (Nordic countries) and €51 million (UK/France).[iv]
- In Europe, 17 power markets have been linked together so far in 2014 as the European Union moves towards establishing an EU Internal Energy Market. The market now represents 75% of today's electricity consumption in the EU and is expected to lead to important cost savings for customers.

Questions for Analysis

1. What lessons can we learn from the most successful market design efforts in the world?
2. What is the optimal geographic extent of balancing areas and design of energy markets?
3. Who will be the winners and losers from integrating balancing areas and moving towards more efficient markets, and how can transition paths be developed that minimize the resistance from, and damage to, the potential losers?
4. How should non-flexible energy be incorporated into the market? Should separate long-term energy and short and long-term balancing markets be created?
5. What features of a balancing market are most important for driving adequate investment in clean flexibility resources?
6. What incentives and market designs are needed to maintain adequate levels of balancing generation, and to incorporate greater offering (and better pricing) of flexibility and demand response from electricity customers?
7. How should a balancing market be coordinated with long-term energy markets to deliver adequate flexibility resources as they are needed? What price signals should be delivered to which customers on the grid?

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[i] FERC. (2010). Section 6 - PJM Performance Metrics and Other Information. In 2010 ISO/RTO Metrics Report.
[ii] Haugen, Dan (2013). Midwest grid operator expanding south, to 'last frontier' for renewables. Midwest Energy News. 5 February. www.midwestenergynews.com.
[iii] NREL (2013). Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection.
[iv] European Commission (2013). Impact Assessment on European Electricity Balancing Market.

DEVELOPING NEW ELECTRICITY DISTRIBUTION OPERATING MODELS TO ACCOMMODATE CUSTOMER GENERATION AND STORAGE WHILE MAINTAINING SERVICES

Overview

Distribution systems take electricity from high voltage, long-distance transmission systems, reduce voltage, and distribute electricity to customers in a local area. Whether unbundled and priced as a separate service or wrapped into a composite energy charge, these services have typically been priced on a per-unit — that is per kWh — basis. When the service provided was almost exclusively energy delivery, that pricing made sense. However, distributed generation — particularly roof top solar — and net metering have the potential to turn the usage and value proposition of a distribution grid on its head.

When using distributed generation, a customer rarely matches real-time generation to energy use. In order to balance, the customer will feed back excess generation to the grid and cover shortfalls by drawing energy from the grid. A household with zero net demand from the grid may nevertheless be frequently using the distribution network to balance its consumption. Even when storage diminishes balancing needs, a customer will most likely need the grid to provide back-up in case, say, 10 days without sun completely depletes the batteries. The customer may no longer have any net demand from the grid but will still rely on the system.

As long as the amount of distributed generation on the system is small, the current model is manageable. However, when the costs of managing the grid are allocated on the basis of net consumption and when a significant amount of consumers have little or no net consumption, costs are loaded disproportionately on those consumers without distributed generation Although distributed generation represents a small fraction of overall electricity production, it may become a sizeable threat to utility companies. As more customers install distributed energy systems, utilities will be forced to increase rates to maintain profits from an ever-decreasing pool of customers. These increasing rates will further drive customers away.

While the growth of distributed generation presents a clear threat to traditional utility models, there are also

Distribution System Overview

Asset Value

U.S.: Approx. $301 billion
EU: Approx. €600 billion for both transmission and distribution

Ownership/Operation Structure

U.S.: 1749 distribution service companies
EU: 2164 distribution service companies

Key Players

U.S.: Investor owned utilities; federal and muni utilities; state regulators
EU: European Distribution System Operators (EDSO). ENTSO-E; Agency for Cooperation of Energy Regulators (ACER); Council of European Energy Regulators (CEER)

significant opportunities. Future distribution systems and technologies will enable greater customization of services to match customer needs. Companies that are able to match these needs will be able to extract greater value than simply delivering kilowatt-hours. Examples are long-term electricity price contracts, new financing and leasing models, and intelligent storage and backup systems. In any case, the distribution grid will still be needed to provide valuable security, backup, and load-following services. Furthermore, with the advent of electric vehicles, new patterns of demand (and new patterns of payment and pricing) are beginning to emerge.

What will enable this paradigm shift? Structural, cultural, and technological constraints remain. The answer to how much distributed generation the grid can handle and who will pay the losses to the industry is hotly contested. However, it is clear that a disruptive trend has emerged.

Current state

- As the installed cost of PV declines from $5/watt to $3.5/watt (a 30-percent decline), the targeted addressable market is expected to increase by 500 percent, including 18 U.S. states and 20 million homes.[i]
- Hawaii, the US state with the highest retail electricity prices, has seen solar rooftop installations surge to the point that the local utility company placed a moratorium on new grid connections due alleged concerns over system stability. This has pitted the local utility against solar developers in the state and is a battle that is bound to replay around the country as installations increase.[ii]
- The California System Operator (CAISO) estimates that scheduled curtailment will be necessary as renewable energy generation increases beyond 33% of load.[iii] Deploying additional flexibility options can greatly improve the management of renewables and decrease curtailment needs.
- The California legislature passed a law in 2013 (AB327) that removes the limits of customer-owned renewable energy generation and allows utilities to charge a fixed charge of up to $10 to residential customers, helping utilities recoup the costs necessary to support growing amounts of renewable energy.
- In Germany, 51% of all installed capacity is owned by individuals. This is largely a result of the dramatic growth of solar rooftops and also of co-op models that have allowed community members, farmers and others to collectively own wind and solar projects.

Questions for analysis

1. How will pricing for distribution services evolve?
2. Will the new pricing mechanisms impact the attractiveness and competitiveness of distributed energy?
3. Will distribution services become local services rather than integrated utility services?

[i] EEI. (2013). Disruptive Challenges□: Financial Implications and Strategic Responses to a Changing Retail Electric Business.

[ii] Chediak, M., Martin, C., & Wells, K. (2014). Utilities Feeling Rooftop Solar Heat Start Fighting Back. Bloomberg News. Retrieved from http://www.bloomberg.com/news/2013-12-26/utilities-feeling-rooftop-solar-heat-start-fighting-back.html

[iii] E3 (2013). Renewable Energy + Flexibility (REFLEX) Results. https://ethree.com/documents/E3_REFLEX_CAISO_2013-12-31_FINAL.pdf

Overview

Until recently, electricity grids seldom communicated with customers. Customers contacted their local utility, connected to the grid, used low cost, reliable electricity at any time, and received relatively simple monthly statements from their regulated supplier. They have been unaware that their usage patterns impose extra costs on the system by requiring more expensive plants to operate and more backup to be built, and they have rarely had an incentive to avoid those costs. As a result they have done little to adjust their demand even though it might cost them remarkably little to do so. The same ease of use, uniform pricing, and lack of information on both their costs and impact have led customers to miss a range of energy efficiency opportunities that would, again, improve overall system efficiency.

With abundant flexible generation on hand and relatively sketchy data on the availability and cost of customer flexibility, the administrative cost and effort to date of accessing this flexibility has probably been greater than its potential value. Now, however, several forces are converging to change the value equation and are likely to drive a major change in the way customers value their energy use and interact with the energy system:

1. The flexibility that customers can offer is becoming more valuable due to the increase in low carbon, less flexible generation.
2. Advances in metering, information technology, communications, and systems management have improved both the quality of information available and the ability to use this data in pricing flexibility and incentivizing customers to provide flexibility and billing for services.
3. Customer-facing technology, such as rooftop solar, plug-in electric vehicles, in-home cogeneration of heat and electricity, and electricity

Customer Management Overview

Number of Customers

U.S.: Approx. 126 mn residential; 19 mn commercial and industrial

EU: Approx. 211 mn residential; 33 mn commercial and industrial

Annual Revenues

U.S.: $164 bn residential; $200 bn commercial and industrial

EU: €111 bn residential; €182 bn commercial and industrial

Key Players

U.S.: Incumbent utilities, ESCOs (including Ameresco, Constellation, Schneider Electric, Metrus, NORESCO), energy efficiency and customer information providers (including Opower, EnerNOC, Silver Spring Networks), competitive retail electric providers, distributed generation companies (e.g., SolarCity), government and third-party efficiency program operators (e.g., Energy Trust of Oregon)

EU: Incumbent utilities, competitive retail electric providers storage, is increasing the opportunity for consumers to participate and invest in both generation and flexibility, creating greater potential benefits to be shared between consumers and electricity suppliers.

4. Retail competition in some jurisdictions is changing the relationship between consumers and suppliers, particularly with the growing potential for innovative competitors to incumbent suppliers.
5. As we are faced with a transition from a fossil fuel-based generation system to a renewable one, all demand-side services (including energy efficiency, load-shifting, and storage) will become relatively more attractive as a way of reducing the total system build necessary for that transition.

These changes have a potential impact far beyond flexibility, as the new business models for retail and the greater potential investment opportunities on the consumer side may bring opportunities for more innovative energy supply services, including financing, energy management, and customer aggregation models that could change the economics for energy efficiency investment as well as flexibility.

But a note of caution is warranted: This transition will not be automatic. In the 1990s, California deregulated energy efficiency services on the theory that private companies would step in to finance efficiency improvements; instead, investment and energy savings declined.[i] Careful policy design and continued public support and guidance will be needed as the current model of utility provision of efficiency and demand response gives way to a more competitive, decentralized model.

Current state

1. Demand-side management programs have grown in the U.S. in recent years. Program administrators spent $6.1 billion on electric demand-side management programs in 2012, including $1.1 billion for demand response and $5 billion for energy efficiency.[ii]
2. Demand response — demand reduction or shifting during peak times to better meet system needs and reduce cost — has been a concerted area of policy development for over two decades. Demand response has grown in the U.S., especially among large industrial and commercial customers, but residential adoption has been slower. Demand response in Europe has had a slower start.[iii]
3. Smart meter penetration, a key enabler of demand management programs, rose from 8.7% penetration in the U.S. to 22.9% between 2009 and 2011, but that growth has been concentrated in a few states and penetration is low across much of the country.[iv]
4. Opt-in variable peak pricing is becoming more popular across the U.S. However, actual opting in has been limited, and high adoption levels probably require a shift to an

opt-out model, which poses a consumer acceptance challenge.

5. FERC has issued a series of orders to enable demand-side resources to participate more easily in wholesale energy markets, including demand response (Order 745) and frequency regulation (Order 755). Following earlier FERC orders, both ISO New England and PJM allow energy efficiency resources to participate in forward capacity markets.
6. Retail competition is growing in both Europe and the U.S.
7. Several new business models have emerged to aggregate and finance demand-side resources, including rooftop solar leasing (e.g., SolarCity) and demand response (e.g., EnerNOC). Other companies are using smart meter data to drive efficiency improvements, through behavioral programs for utility customers (e.g., Opower) or as a service to building owners (e.g., FirstFuel).
8. Energy service companies (ESCOs) have made progress in removing informational, technical and financial barriers to more efficient electricity consumption, though their model of performance contracting has been more successful in the public and institutional sectors than in others. New variants on the ESCO model (e.g., energy services agreements) that target other sectors continue to emerge but have not yet attained large scale.
9. According to a 2009 FERC study, in an aggressive but achievable scenario, demand response capacity could reach 138 GW by 2019, which is the equivalent of roughly 1,840 peaking plants (at 75 MW each).[v]

Questions for Analysis

1. How can electricity markets and rate structures best be adapted to appropriately value the varied demand-side services needed?
2. How will services including distributed generation, storage, energy efficiency, and electric vehicle infrastructure be financed, and how will this affect their cost?
3. What types of companies are best placed to deliver these products and services?
4. What further technological advances are needed, and what role should public policy play in encouraging their development?

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[i] Martinez S, Wang D, Chou J. 2010. California Restores its Energy Efficiency Leadership: Smart Policies Provide Enormous Economic and Environmental Benefits. Natural Resources Defense Council.

[ii] Consortium for Energy Efficiency (2014). 2013 State of the Efficiency Program Industry.

[iii] St. John J. 2013. Europe's New Models for Demand Response. Greentech Media [Internet]. Available from: http://www.greentechmedia.com/articles/read/europes-new-models-for-demand-response

[iv] Federal Energy Regulatory Commission (2012). Assessment of Demand Response & Advanced Metering. Lacey S. 2013. The US Smart Meter Market Is Far From Saturated. Greentech Media [Internet]. Available from: http://www.greentechmedia.com/articles/read/smart-meter-penetration

[v] The "Achievable Participation" scenario assumes that 1) advanced metering infrastructure (smart meters) are universally deployed, 2) dynamic pricing tariffs were the default and 3) other DR programs such as direct load control were available to those who opt out of dynamic pricing. Source: FERC (2009) *A National Assessment of Demand Response Potential*