A Comparative Case-Study Analysis of the Effectiveness and Efficiency of Policies that Influence the Financing of Renewable Energy Projects: U.S. and Europe

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Executive Summary

Finance is a key determinant of renewable policy success. In some way, it will determine whether renewable targets are met and how much it will cost to meet them. And the challenge is big. According to the International Energy Agency (IEA) World Energy Outlook for 2010, $6 trillion will need to be invested in renewable electricity and biofuels over the next 25 years, just to meet current emissions reduction commitments.

CPI's Renewable Energy Finance project assesses the impact of policy on the availability and mix of renewable energy investment. This paper analyzes the link between policy and finance – how policies influence renewable project economics, financial structures, risks, rewards, as well as the allocation of risks and rewards – using the examples of six actual renewable projects in US and Europe. Based on these studies we have found that:

1. Policy is not generally resulting in overpayment:
   - With the exception of the Italian utility-scale solar photovoltaic (PV) facility, financing and project costs are within the range that investors expect and need to make the investment.
   - All the projects still rely on cost or revenue supports to provide revenues commensurate with the risks borne by investors. These supports range from 25% to 75% of costs or revenues depending on the type of project.

2. Policy affects various classes of investors differently:
   - Equity, debt, and mezzanine investors all have different return requirements and risk appetites which affect policy outcomes.
   - Institutional investors control large amounts of capital, and should be natural investors in this space. While they are not yet large investors in renewables, they have been willing to support renewable investments given revenue certainty from policy and arrangements to insulate them from completion and policy risks.

3. Policy can impact finance through several pathways:
   - **Revenue certainty**: policies such as FiT, FiP, or an RPS mitigate or eliminate power market risks which would otherwise be the dominant source of revenue uncertainty and make financing more difficult.
   - **Risk perceptions**: Simple and stable policies reduce perceived risk and may lower financing costs. U.S. policies appear to be overly complex, while some European policies could benefit from greater stability.
   - **Risk distribution**: Having government or ratepayers assume some risks is most important for innovative projects, where some large, undiversifiable risks may make a project unfinanceable by the private sector alone.
   - **Duration**: Policy duration plays an important role in determining the mix of financing available to a project. Too short a term may make a project unfinanceable, but longer terms can increase the cost to government or ratepayers.
• **Cost and Completion certainty:** Policy may be needed to reduce these risks for innovative projects, but for other projects these can be handled through contractual rather than policy arrangements.

• **Development process cost & timing certainty:** Increased risk of project failures at the development stage increases the costs per successful project and reduces the attractiveness of clean energy investment in general. The result can be lower competition and can drive up the returns required to attract investors.

**Continuing and Future Work**

Based upon these findings, we’ve identified some key questions for follow-up work:

• What are the key policy impact pathways most relevant to each class of investor?

• Can we quantify a reduction in the cost of financing or other benefits to stakeholders associated with the increased revenue certainty provided by FiT, FiP, and PPAs? Is this commensurate to the cost of providing such certainty?

• Do differences in policy support structures and the corresponding political risks between the U.S. and Europe influence risk perceptions and ultimately financing costs?

We welcome input on the relevance and value of addressing these questions. This analysis is primarily focused on impacts at the project level. Many key impacts of policy on investor decision making ultimately operate in the context of the full portfolio of investment choices already made or under consideration. How do the policy impacts we have identified at the project level roll up to change investor capital allocation decisions and either bring in new capital or create barriers to such activities? Ultimately, these decisions are critical to diagnosing why a policy does or does not result in realizing its goals. These issues are beyond the scope of the present work, but will be a focus of future work at CPI.
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1 What can project finance case studies tell us about renewable policy effectiveness?

Effective renewable energy policy would encourage the provision of enough renewable energy to meet policy objectives, drive innovation and cost reduction for new technologies, and do so cost effectively, equitably, and without introducing significant risks. Where companies or other private sector investors are the main source of funding to meet these goals, financing lies at the heart of their decision making process and has a crucial impact on how much renewable energy these investors decide to provide, at what cost, and with what associated risks. In other words, financing is a key determinant of the effectiveness of renewable policy.¹

Renewable projects, their investors, and the policy environments in which they might operate, are diverse and heterogeneous. Thus, there is no single prescription that tells us how to design policy that will get renewable projects financed effectively. In this paper, we identify some general principles about how policy influences investment decisions, with a view towards building tools to help policy-makers design policies which can effectively and efficiently leverage investment in the renewable space. To do so, our analysis and discussion is several parts:

- First, we set out the specific mechanisms, or pathways, through which policy can impact the financeability of renewable projects.

- Next, we explore the different types of investors that might participate in renewable energy projects and begin to draw the links of how each of these policy “impact pathways” would affect their investment decisions.

- As a third step, we have studied a series of cases based on real world renewable energy projects in the U.S. and Europe, applying this framework of policy impacts on potential investor types, to understand how policy has affected – or could have affected – the investment decision, costs and risks.

- Finally, we will bring the findings from these case studies together to identify where there may be common lessons and under which circumstances these lessons might be applicable.

2 What are the pathways by which policy impacts project financing?

In general, policy can affect the investment environment by influencing the allocation of costs and revenues, the allocation of risks, and the technology choices and business practices of electricity market participants and other key stakeholders. From our analysis of the six cases discussed below as well as interviews with a range of stakeholders we find that these influences can be best understood through the following policy impact pathways:

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¹ In CPI’s “Renewable Energy Financing and Climate Policy Effectiveness” Working Paper, we explored how financing can be used to diagnose policy effectiveness outcomes, focusing on deployment of renewable energy, cost-effectiveness, distribution of risks, costs and benefits, innovation outcomes, and policy stability as key policy effectiveness criteria.
Revenue certainty
Revenue streams from the sale of renewable electricity generating projects can be volatile – for example, due to variability of the wind or solar resource, poor technology availability, and/or changing market prices for the electricity generated. Investors may demand a premium to bear these risks, and policies which can either directly or indirectly improve revenue certainty can help reduce these costs.

Risk perception
Investor perceptions of project risks play a significant role in determining the amount and cost of financing made available. Such perceptions can be significantly tied to policy regimes – investors are likely to demand a premium for projects which depend on substantial, ongoing incentives to compete depending on their perceptions the political sustainability of the incentives. These perceptions will vary by region and over time.

Risk distribution
Different investors are comfortable bearing different risks: they may have business processes to reduce certain risks or may even have offsetting risks. Policy can influence the allocation of risks among project stakeholders or reduce the impact of these risks on financing costs and thereby broaden the base of interested investors.

Duration
The term of a project’s financing is often directly linked to the duration of policy support measures. Different classes of investors have different investment horizons, and their investment decisions are strongly influenced by a project’s financing term.

Cost certainty
Construction and operational cost uncertainties can substantially impact investor returns. Policy requirements which lead to the establishment of various reserve accounts or performance guarantees – as well as up-front incentives – can reduce these risks or shift them other stakeholders comfortable with bearing them.

Completion certainty
Timing of completion and operation is often critical for meeting investor return requirements, and the risk that a generating facility based on a new technology cannot meet its target operational date is one that few investors are willing to bear without substantial premiums. Policy can often substantially impact or shift the burden of these risks.

Development process cost & timing certainty
Only a fraction of projects in a development pipeline ever get built, due to barriers such as competing outside stakeholder interests or regulatory delays or impediments. Policies which can reduce development timeframes and increase success rates can substantially improve developer capital efficiency and returns and attract investor interests.

European and U.S. policies differ in their influence pathways, and these differences can help explain some of the significant differences in outcomes observed.

3 Who are the potential investors and what do they care about?
A range of financial instruments are used provide capital to renewable energy projects. These financial instruments include multiple types of debt, equity, and mezzanine finance. The return requirements of these investors, as well as the mix of finance types used, ultimately determine the cost of capital of a
The following description of investor characteristics draws from earlier CPI work framing our approach to effectiveness analysis in renewable finance [CPI (2011)].

3.1 Investor Characteristics

**Debt investors** bear the least risk, and expect the lowest returns. They generally do not invest in projects that use unproven technologies, and often require contractual arrangements that protect them from technology-related delays or underperformance. Similarly, debt investors are wary of policy and regulatory risk when cash flows depend on policy support. Debt investors usually earn a specified coupon rate, or a specified margin above a benchmark interest rate.²

Debt investors are particularly concerned with the default risk of their investment. Providers of debt conduct rigorous assessments of project risks, scenarios in which the borrower would default on their debt, and the likelihood of those scenarios. The assessment of default risk determines whether project debt is “investment grade” – an important consideration for many institutional investors.

The debt service coverage ratio (DSCR) – cash flows available for debt service divided by debt service payments – is an important metric in assessing default risk. Lenders to wind projects look at the debt service coverage ratio under a variety of wind resource scenarios. For example, they might require that low wind conditions with a 10 percent chance of occurring generate sufficient cash flows to cover 1.2-1.4 times the amount of debt payments. Certain contractual conditions may be used to maintain adequate debt service coverage, like cash sweeps³ or sculpted amortization schedules.⁴

**Mezzanine investors** have a variety of investment objectives. They might require the predictability of returns offered by debt-like instruments, while tolerating more default risk than debt if it affords them a higher rate of return. They might prefer equity

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² When a debt instrument carries a fixed interest rate, this is typically referred to as the “coupon rate.” When a debt instrument specifies a margin rather than a fixed rate, the margin is usually measured in basis points above an interbank rate, such as LIBOR or EURIBOR.

³ Cash sweeps capture cash flows that would not be used to service debt for advance repayment of debt principal and interest. This contractual clause is designed to protect debt investors from unexpectedly low project cash flows. Cash sweeps reduce the amount of project cash flow available for project equity investors.

⁴ Sculpted amortization allows debt service payment amounts to vary with cash flows, to account for variation in cash flows across seasons. This is another way of protecting debt investors from low project cash flows, by capturing additional payments when cash flows are high. Sometimes amortization schedules are sculpted to maintain a constant debt service coverage ratio.
with a capped return in exchange for limited exposure to equity risks.

Tax equity is a mezzanine investment instrument generated by the structure of tax incentives for renewable energy in the US. Tax equity investors realize returns primarily based on tax credits for investment in or production of renewable energy and tax benefits derived from accelerated depreciation of a project’s capital cost. Tax equity investors must have sufficient tax liability to absorb these tax benefits. Tax equity investors are protected from many of a project’s cash flow and revenue risks, but because their return relies entirely on tax and depreciation policy, they are exposed to regulatory risk, should tax and depreciation policy change.

**Balance sheet equity investors** are typically large utilities that finance new projects entirely from their own capital. By providing all of the capital required to build a project, they also take on most or all of the project risks. Balance sheet investors generally look at the internal rate of return (IRR) or return on equity (ROE) of a project as a metric of profitability. This IRR is usually compared with the company’s cost of capital, as well as a “hurdle rate” designated for a particular type of project, given its risk profile.

**Project finance equity investors** take an ownership stake in their projects as well, often coupled with other equity partners, mezzanine investors and debt. In project finance arrangements, equity investors bear the most project risks, and are compensated with higher potential returns. Equity investors, often also the developers of projects, can use leverage to increase their return. However, increased leverage also concentrates project risks with a smaller amount of capital. Because project developers have control over many aspects of a project, they may be better suited to manage or mitigate project risks.

When equity is invested alongside debt, the metric of interest is usually a “levered IRR”, the rate of return after debt is serviced. Equity investors evaluate the rate of return they receive given the risks they absorb. In this sense, equity investors are most interested in the risk-adjusted rate of return on their investment.

<table>
<thead>
<tr>
<th>Investor Type</th>
<th>Risk Requirements</th>
<th>Metrics of Interest</th>
<th>Cost of Capital</th>
</tr>
</thead>
<tbody>
<tr>
<td>Debt</td>
<td>Low risk tolerance, generally will not bear technology or completion risks, typically insulated from operational risks.</td>
<td>Debt service coverage ratio (DSCR), Margin or Interest Rate</td>
<td>Low</td>
</tr>
<tr>
<td>Mezzanine</td>
<td>Somewhat low risk tolerance, will bear some operational risks, but generally not completion risks.</td>
<td>IRR, Interest Rate and Default Probability (for Fixed-Income Instruments)</td>
<td>Low – Medium</td>
</tr>
<tr>
<td>Balance Sheet Equity</td>
<td>Bears all project risks.</td>
<td>IRR, other metrics relevant to internal decision-making</td>
<td>Medium</td>
</tr>
<tr>
<td>Project Finance Equity</td>
<td>High risk tolerance, willing to concentrate project risk by increasing project leverage.</td>
<td>Project IRR, Levered IRR</td>
<td>Medium - High</td>
</tr>
</tbody>
</table>
3.2 Return Benchmarks

We will be presenting after-tax (levered, if debt is involved at the project level) IRRs for various equity investors as one primary output of our financial models. We provide some recent published estimates of returns for renewable projects in the U.S. and Europe as benchmarks.

Estimated U.S. Returns
The following table from [Mintz Levin (2010)] provides an estimate of rates of return typically expected by U.S. project investors.

<table>
<thead>
<tr>
<th>Finance Type</th>
<th>Technology</th>
<th>Rate of Return</th>
<th>Availability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Term Debt</td>
<td>Wind</td>
<td>LIBOR + 250-300bp</td>
<td>High</td>
</tr>
<tr>
<td></td>
<td>Solar PV</td>
<td>6.5-7.5%</td>
<td>Fair to High</td>
</tr>
<tr>
<td></td>
<td>CSP</td>
<td>7.5-10%</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>8-12%</td>
<td>Low</td>
</tr>
<tr>
<td>Unlevered Tax Equity</td>
<td>Wind</td>
<td>7-10%</td>
<td>Fair</td>
</tr>
<tr>
<td></td>
<td>Solar PV</td>
<td>9-13%</td>
<td>Fair to Low</td>
</tr>
<tr>
<td></td>
<td>CSP</td>
<td>12-15%</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>10-12%</td>
<td>Low</td>
</tr>
<tr>
<td>Levered Tax Equity</td>
<td>Wind</td>
<td>10-13%</td>
<td>Fair</td>
</tr>
<tr>
<td></td>
<td>Solar PV</td>
<td>13-20%</td>
<td>Fair to Low</td>
</tr>
<tr>
<td></td>
<td>CSP</td>
<td>15-18%</td>
<td>Low</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>13-15%</td>
<td>Low</td>
</tr>
<tr>
<td>Sponsor or Private Direct Equity</td>
<td>Wind</td>
<td>6.5-14.5%</td>
<td>High</td>
</tr>
<tr>
<td></td>
<td>Solar PV</td>
<td>7-18.5%</td>
<td>Fair</td>
</tr>
<tr>
<td></td>
<td>CSP</td>
<td>15-20%</td>
<td>Fair to Low</td>
</tr>
<tr>
<td></td>
<td>Geothermal</td>
<td>10-15%</td>
<td>Low</td>
</tr>
</tbody>
</table>


European Return Benchmarks
Similarly we have estimated some corresponding benchmarks for returns observed for renewable projects in European countries:

<table>
<thead>
<tr>
<th>Finance Type</th>
<th>Technology</th>
<th>Rate of Return</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Term Debt</td>
<td>Onshore Wind</td>
<td>EURIBOR + 200-300bp</td>
<td>Project Finance Magazine</td>
</tr>
<tr>
<td></td>
<td>Offshore Wind</td>
<td>EURIBOR + 300bp+</td>
<td>Project Finance Magazine</td>
</tr>
<tr>
<td></td>
<td>PV</td>
<td>EURIBOR + 250-350bp</td>
<td>Project Finance Magazine</td>
</tr>
<tr>
<td>Unlevered Equity</td>
<td>Onshore Wind</td>
<td>5-9%</td>
<td>Macquarie</td>
</tr>
<tr>
<td></td>
<td>Offshore Wind</td>
<td>4-13%</td>
<td>KPMG</td>
</tr>
<tr>
<td></td>
<td>PV</td>
<td>10-11%</td>
<td>Solar Energy Partners</td>
</tr>
<tr>
<td>Levered Equity</td>
<td>Onshore Wind</td>
<td>8-16%</td>
<td>Macquarie</td>
</tr>
<tr>
<td></td>
<td>Offshore Wind</td>
<td>NA</td>
<td>Solar Energy Partners</td>
</tr>
<tr>
<td></td>
<td>PV</td>
<td>15-18%</td>
<td>McKinsey via GRE Holding</td>
</tr>
</tbody>
</table>
What do the six cases tell us about how policies impact investor decisions?

We use the policy impact pathways introduced above to study policy influences on the financing of six case studies based on publically available information on specific renewable projects. CPI developed the financial model described in Appendix A to enable a quantitative assessment of these impacts on the projects studied. We have used publicly available data, interviews, and financial modeling to draw lessons from the six cases described in the table below:

<table>
<thead>
<tr>
<th>U.S. Cases</th>
<th>Description</th>
<th>Key Issues</th>
</tr>
</thead>
</table>
| Generic U.S. Wind based on First Wind Milford (Utah) | • An estimated $445 million, 204 MW wind farm  
• Assumed tax equity financing and a long term PPA with a California utility in response to 2007 request for proposals | • Allocation of costs, risks, and rewards of tax equity financing  
• Are tax equity structures just costly responses to policy or can they also attract new capital? |
| Utility Scale PV based on Greater Sandhill (Colorado) | • An estimated $94 million, 19 MW PV installation by SunPower  
• Attracted debt and equity investment by institutional investors (John Hancock, MetLife)  
• Long-term, above market PPA awarded to meet state solar generation standard | • How did policy help attract institutional investors to this project? |
| Solar Power Tower based on BrightSource Ivanpah (California) | • $2.2 billion, 392 MW solar power tower to be built with a $1.6 billion government loan  
• Attracted $598 million in private financing, including a $168 million tax-motivated investment from Google | • How did policy attract investment in a first-at-scale facility, and were all the policies used necessary?  
• How did policy allocate risks and rewards among stakeholders? |

<table>
<thead>
<tr>
<th>European Cases</th>
<th>Description</th>
<th>Key Issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generic Spanish Wind based on Villanueva (Spain)</td>
<td>• 130 million EUR, 70 MW On-shore wind farm</td>
<td>• How do market price risks and policy risks in Spain’s Feed-in-Premium (FiP) and Feed-in-Tariff (FiT) support schemes impact investors?</td>
</tr>
</tbody>
</table>
| Utility Scale PV based on Rovigo (Italy) | • 275 million EUR, 60 MW PV installation  
• Received a significant Italian FiP | • The oversubscription of the FiP led to very high program costs and retroactive changes to the FiP. How did such changes impact risk perception and financing costs? |
| Offshore Wind based on Anholt (Denmark) | • 9.3 billion DKK (1.4b EUR), 400MW Offshore wind farm  
• Pre-completion commitment of funding from a Danish Pension Fund | • How did policy help attract institutional investors to this project? |

In section 4.1 we describe the U.S. cases and policy impacts in detail, and we move on to the European cases in Section 4.2.
4.1 U.S. Cases and Policies

Generic U.S. Wind based on First Wind Milford (Utah)
We used the key cost, performance, and other key features of the 204 MW Milford wind farm developed by First Wind as well as some generic features of First Wind’s financing approach as a proxy to build a model for a generic U.S. wind project. In particular, we explored the risk and return characteristics of the project assuming the use of a tax equity flip financing arrangement, common in the U.S. to take advantage of tax benefits such as accelerated depreciation. As was the case for Milford itself, we assume the project utilizes a tax grant and that it was built to deliver electricity to help satisfy a California RPS through a long-term PPA. Key policy impact questions here are focused on the impact of the PPA on financing costs and the impact of various incentives on investor risks and returns.

Utility Scale PV based on Greater Sandhill (Colorado)
The 19 MW Greater Sandhill Photovoltaic project was fully commissioned in March 2011 in Colorado’s Alamosa County. It is one of the largest deployments of solar PV technology in the US. The project relies on a range of renewable energy policies, including Colorado’s RES, the US tax grant, and potentially, 100% bonus depreciation and Alamosa County tax credits. The project attracted tax-motivated equity and debt financing from two major institutional investors. Key policy impact questions here are focused on how policies enabled investment by institutional investors.

Solar Power Tower based on BrightSource Ivanpah (California)
The Ivanpah Project, currently under construction, will be the largest solar thermal electricity generating facility in the world when it begins operating in 2013. The 392 MW, $2.2 billion facility consists of three power towers, being built in phases and substantially as a result of U.S. federal and state policies:

- a $1.6 billion federal loan guaranteed by the U.S. DOE,
- an estimate $570 million cash grant,
- accelerated depreciation,
- lease of federal lands,
- a long term PPA with utilities bound by California’s RPS, and
- exemption from property taxes for solar property.

The developer was able to use the government investment to bring in substantial private capital from outside investors, including a relatively new tax-motivated investor to this space. Key policy impact questions for Ivanpah include how this mix of policies combined to make the project viable, and how they allocated risks and rewards among government and private stakeholders to enable significant private investment in scale-up of this innovative technology.

U.S. Renewable Policies

U.S. Department of Energy (DOE) Loan Guarantee
The DOE guarantees loans made to renewable projects by private lenders or by the U.S. Federal Financing Bank. The cost to the DOE of providing the guarantee is being covered by funds made available by the U.S. Recovery Act of February, 2009.

Tax Credits and Grants
U.S. wind projects built by 2013 are eligible for production tax credits (PTC: $0.02 per kWh for 10 years), and solar built by 2017 for investment tax credits (ITC: 30% of eligible project costs). If they begin construction by the end of 2011, they can apply for a grant in lieu of either tax credit for 30% of eligible project costs. These grants were authorized by Section 1603 of the Recovery Act.

Accelerated and Bonus Depreciation
Renewable projects can accelerate the rate of depreciation for tax purposes of their renewable property from the life of the project down to 5 years. In addition, projects placed into service by the end of 2011 (2012) can claim 100% (50%) bonus depreciation (depreciation of 100% (50%) of the property’s value in the first year).

Use of Federal Lands
The U.S. leases Federal lands for renewable generation, with payments set using rural land market value benchmarks with a surcharge for solar property use.

Renewable Energy or Portfolio Standard (RES or RPS)
Demand for renewable electricity in states are often driven by requirements that load-serving utilities derive a target fraction of their electricity generation from (non-hydroelectric) renewable sources by a target date. To meet this requirement, many utilities have been offering long-term power purchase agreements (PPAs) to project developers at the avoided cost to the utility of financing the generation itself.

Property Tax Exemptions for Renewable Property
A number of states exempt renewable facilities from property taxes in order to attract investment.

Sales Tax Exemption
A number of U.S. states exempt purchases of equipment or services for renewable electricity generating facilities from sales / use taxes.
U.S. Case Results

- **Returns**: Equity returns for projects are in line with expected ranges published by Mintz Levin.

- **Revenue and cost support mechanisms**: Tax-related incentives cover roughly 35-50% of levelized project costs. Revenue support through price premiums implicit in long term power purchase agreements (PPA) offered by utilities in response to state RPS / RES cover and additional 10-35% of project costs.

- **Impact of policies on project costs and returns**: U.S. projects make use of multiple revenue and cost support measures from various levels of government. While the total levels of support were substantial, we found that unit costs of these facilities were in line with or below estimates for similar facilities. Thus, it appears that achieving the appropriate level of return was down to reasonable policy setting rather than suppliers bidding up project costs to increase margins.

- **Tax incentives and mezzanine investment**: The prevalence and importance of tax equity may preclude some other, more innovative, mezzanine financing structures. The significance of this and the cost of using tax equity as the support vehicle both merit further research.

- **Revenue certainty**: PPAs eliminate risks associated with uncertain revenues due to variations in expected future market prices for electricity. As market price variability is generally a larger risk to revenues than resource variability or technology availability, revenue certainty likely enables lower financing costs. We are investigating the relationship between the degree of revenue certainty and financing costs.

- **Risk perceptions**: Dependence on multiple incentives exposes the project to potential regulatory uncertainty (application process / changing rules) and policy uncertainty (sustainability of incentives in severely constrained fiscal environments) associated with each incentive. The extent to which the existence of multiple incentives increases risk perceptions and financing costs remains unclear, but deserves further investigation.

- **Risk Distribution**: In the case of an innovative project like Ivanpah, a loan guarantee can shift some of the burden of a catastrophic failure of a project to government. The existence of potential catastrophic failures – which are most common in innovative, first-of-a kind projects – could make a project impossible to finance in the private sector at any reasonable expected return.

- **Duration**: The duration of the PPA available to each of these projects was closely tied to the duration of long-term financing the project was able to obtain. The term of financing and support duration were explicit considerations of policymakers in designing the support policy. Whether the durations set were optimum remains an open question, but the financeability of the projects and reasonable returns indicate that the term was at least reasonable.

- **Cost and completion certainty**: Cost certainty and completion certainty can be handled through contractual rather than policy arrangements, except for innovative projects.

- **Development process cost & timing certainty**: Increased risk of project failures at the development stage increases costs and reduces the attractiveness of clean energy investment in
general. The result can be lower competition and can drive up the returns required to attract investors. Policy impacts through the development process can be important, but are best understood through analysis at the portfolio rather than project level. We are currently investigating these impacts.

Key Modeling Assumptions

<table>
<thead>
<tr>
<th></th>
<th>Generic U.S. Wind based on First Wind Milford</th>
<th>Utility Scale PV based on Greater Sandhill</th>
<th>Solar Power Tower based on Ivanpah</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Size</td>
<td>203.5 MW AC</td>
<td>18.5 MW AC</td>
<td>376.6 MW AC</td>
</tr>
<tr>
<td>Production</td>
<td>450,953 MWh / Yr</td>
<td>48,004 MWh / Yr</td>
<td>975,000 MWh / Yr</td>
</tr>
<tr>
<td>Project Cost</td>
<td>445m USD</td>
<td>94m USD</td>
<td>2.2b USD</td>
</tr>
<tr>
<td>Grant Amount</td>
<td>120.1m USD</td>
<td>25.4m USD</td>
<td>570m USD</td>
</tr>
<tr>
<td>First-Year PPA Rate</td>
<td>98.4 USD / MWh</td>
<td>147 USD / MWh</td>
<td>154 USD / MWh</td>
</tr>
<tr>
<td>PPA Duration</td>
<td>20 Years</td>
<td>20 Years</td>
<td>25 Years</td>
</tr>
<tr>
<td>First-Year Market Rates</td>
<td>68 USD / MWh</td>
<td>53 USD / MWh</td>
<td>80 USD / MWh</td>
</tr>
<tr>
<td>Fixed O&amp;M</td>
<td>28.07 USD / kW-Year</td>
<td>21.55 USD / kW-Year</td>
<td>64.00 USD / kW-Year</td>
</tr>
<tr>
<td>Accelerated Depreciation</td>
<td>5-Year MACRS</td>
<td>5-Year MACRS, does not apply with 100% bonus</td>
<td>5-Year MACRS</td>
</tr>
<tr>
<td>Bonus Depreciation</td>
<td>50%</td>
<td>100%</td>
<td>0%</td>
</tr>
<tr>
<td>Base Case Term Debt</td>
<td>1.4x</td>
<td>1.4x</td>
<td>1.4x</td>
</tr>
<tr>
<td>Required Min DSCR</td>
<td>7.028%</td>
<td>7.028%</td>
<td>4.7%</td>
</tr>
<tr>
<td>Outside Equity Hurdle</td>
<td>9%</td>
<td>9%</td>
<td>15%</td>
</tr>
<tr>
<td>LCOE Discount Rate</td>
<td>8.25%</td>
<td>8.25%</td>
<td>7.88%</td>
</tr>
</tbody>
</table>

**Sources:**
Ivanpah: BrightSource S-1, US Treasury, EIA, BLM Record of Decision for Ivanpah, California MPR Model, CPUC Approval of SCE and PG&E PPAs. Time-of-day factors are modeled as a 20% premium added to estimated Ivanpah PPA and market rates relative to MPR rates / forecasts. Further, a fraction of the tax grant (assumed as needed to achieve the min DSCR) is assumed to pay down principal on the DOE term debt, as noted in the case of Kahuku Wind’s loan guarantee in First Wind’s S-1.
4.1.1 Levelized Cost Comparison
We calculate the contributions of policies to levelized cost of energy (LCOE) by starting with a “Counterfactual LCOE” which includes capital costs and operating expenses (excluding any tax concessions which might reduce either), and includes tax benefits from 20-year straight line depreciation. We use a utility cost of capital (varying slightly by case to reflect local utility returns, but all very close to 8%) as a discount rate to get a reasonable estimate for the cost of electricity in the absence of incentives. We then add in the impact of cash flows associated with cost-based incentives. Finally, we add the impact of financing cash flows (relative to the assumed utility discount rate) to arrive at the final LCOE.

Similarly, we calculate levelized after-tax revenues by calculating the levelized revenue stream from a forecast of expected market rates and then adding in the contribution of additional sources, including cash incentives and feed-in premia and incremental revenue from an above-market PPA or tariff.

The results of these calculations, presented in figures 1 through 3, show several key aspects of U.S. renewables project.

- A large contribution of overall cost reductions come from up-front, cost-based incentives such as the tax grant and accelerated depreciation policies.

- At least some degree of revenue support, provided by an above-market PPA. This incremental revenue support varies by technology and local electricity market prices.

- The Generic Wind and Utility-Scale PV cases involve financial structures that do not differ substantially from utility costs of capital. The Solar Power Tower case involves a loan guarantee, which constitutes a relatively large reduction in project costs associated with financing.

Market Price and PPA Price Assumptions
We use EIA’s Annual Energy Outlook 2011 reference case electric power price projection for generation in the WECC-California region (Table 92) as a proxy for expected future wholesale electricity market prices for Ivanpah (adjusted for time-of-day factors) and Milford, and WECC-Rockies region (Table 94) for Greater Sandhill. Further, for both our cases selling power to California utilities, we assumed that PPA prices were consistent with the appropriate California Public Utility Commission (CPUC) Market Price Referent (MPR). The CPUC publishes an MPR each year which provides a benchmark (an “avoided cost”) used to judge the reasonableness of PPAs signed by California’s major Investor Owned Utilities to meet their requirements under California’s RPS. The MPR is calculated by assuming that generation needs would otherwise met by a new 500 MW combined-cycle gas turbine built in the same year as the proposed renewable facility. The calculation assumes an increasing carbon price consistent with California’s implementation of a cap and trade regime for carbon emissions.
**Generic U.S. Wind based on First Wind Milford**

Tax grant and depreciation benefits are major policy supports on the cost side, combining to cover roughly 35% of costs. We have assumed that this generic wind project sells its generation to an investor-owned California utility through a long-term PPA with a price equal to the appropriate California MPR. Note that Milford’s generation is actually being sold to a California municipal utility through a pre-paid PPA – an arrangement we hope to study in future work. Comparing the PPA price to these market rates, we find that the PPA provides the project with a premium of roughly 20% above market rates. As these prices include the expected impact of the RPS, we attribute the incremental price of the PPA as reflecting a premium associated with the carbon price assumed in the MPR.

**Figure 1 – Levelized Costs and Revenues for Generic U.S. Wind based on First Wind Milford**
Utility Scale PV based on Greater Sandhill

The Treasury grant and depreciation tax benefits cover 44% of levelized project costs. The incremental revenue above prevailing market rates enables the project from the revenue side. We attribute the incremental price of the PPA as reflecting a premium associated with the solar REC.

**Figure 2 – Levelized Costs and Revenues for Utility Scale PV based on Greater Sandhill**

<table>
<thead>
<tr>
<th>Description</th>
<th>Value (USD / MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Counterfactual LCOE</td>
<td>184</td>
</tr>
<tr>
<td>Tax Credits and Grant</td>
<td>51</td>
</tr>
<tr>
<td>Property Tax Concessions</td>
<td>-2</td>
</tr>
<tr>
<td>Sales / VAT Tax Concessions</td>
<td>-18</td>
</tr>
<tr>
<td>Depreciation Tax Benefits</td>
<td>30</td>
</tr>
<tr>
<td>LCOE After Tax Benefits and Grant</td>
<td>101</td>
</tr>
<tr>
<td>Financial Structure and Reserves</td>
<td>6</td>
</tr>
<tr>
<td>Final LCOE after Financing</td>
<td>107</td>
</tr>
<tr>
<td>Final After-Tax Levelized Revenues</td>
<td>107</td>
</tr>
<tr>
<td>Cash Incentive or Premium</td>
<td>-</td>
</tr>
<tr>
<td>REC Revenue</td>
<td>-</td>
</tr>
<tr>
<td>Incremental PPA or Tariff Revenue</td>
<td>68</td>
</tr>
<tr>
<td>After-Tax Revenues at Market Rates</td>
<td>39</td>
</tr>
<tr>
<td>Levelized Costs and Revenues (USD / MWh)</td>
<td>0 - 200</td>
</tr>
</tbody>
</table>
Solar Power Tower based on Ivanpah

U.S. Federal tax grants, depreciation benefits, and loans were responsible for cutting in half the cost of electricity from the project. The PPA price offered by California utilities (adjusted for time of day factors) under the RPS in 2008 represents a 50% premium above expected wholesale market prices for electricity. When this premium is combined with the property tax exemptions, California governments and ratepayers are bearing an additional 20% of the costs.

Figure 3 – Levelized Costs and Revenues of Solar Power Tower based on Ivanpah
4.1.2 Generic U.S. Wind (from First Wind Milford in Utah)

On-shore wind is still by far the dominant renewable electricity generation technology deployed in the U.S. These projects often utilize tax equity financing to monetize the value of the tax incentives they receive – accelerated depreciation as well as production and investment tax credits. Further, they generally sell their output through long-term power purchase agreements (PPAs) which are usually offered in the context of a state RPS. Here, we use the technical characteristics of the Milford plant and consider a generic wind base case which is financed through levered tax equity and sells its generation to an investor-owned California utility through a long-term PPA with a price equal to the appropriate California MPR. We assume that the tax equity arrangement is consistent with the generic features described by First Wind in its S-1 filing with the SEC. We find that for our generic wind case:

- The combined returns for all equity investors (11%) for the project are consistent with expectations (a range of 10-13% in Mintz Levin).
- Combined returns for all equity investors would fall below expectations if no accelerated depreciation was available (6%) or could not be monetized through a tax equity arrangement (7%), no tax grant or credit was available (2%), or if the tax grant was replaced by the PTC (8%). However, loss of bonus depreciation alone did not push returns below expectations (10%).
- The tax grant and accelerated depreciation combine to cover roughly 35% of project costs.
- The revenue support provided by the project’s PPA provides a 20% levelized premium over EIA forecasts for future market rates in California.
- The PPA eliminates revenue risks associated with market variability. Without the PPA (but with the premium over market rates), market prices at the lower end of expectations (one standard deviation or 24% below EIA forecasts) would drop equity returns to 3%.
- The remaining revenue risks are borne by equity investors. Sustained expected annual production 8% above or below expectations (roughly one standard deviation) would lead to a range of combined equity returns between 8-15%.
- The combined returns for equity investors would still fall within expectations if the project could not find a debt investor willing to lend to the project at typical market terms (8% equity return versus expectations of 7-10% in Mintz Levin for unlevered equity).
- The duration of tax equity investment is tied to the duration of the tax policy – a PTC for 10 years requires 10 years for the tax equity investor to meet their hurdle rates while a much quicker exit is possible with an ITC. Which of these is available and used more frequently can therefore impact the turnover of tax equity capital, potentially influencing both cost and availability of financing.

**Selected Sensitivities**

<table>
<thead>
<tr>
<th><strong>Base Case</strong></th>
<th>Estimate Equity IRR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Revenue Support and Certainty</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Loss of Implied Premium</td>
<td>5% IRR</td>
<td>38%</td>
</tr>
<tr>
<td>Varying Market Price Expectations w/o PPA (±25%)</td>
<td>3% - 15% IRR</td>
<td>35% - 60%</td>
</tr>
<tr>
<td>Production Expectations (±8%) with PPA</td>
<td>8% - 15% IRR</td>
<td>50% - 62%</td>
</tr>
<tr>
<td><strong>Risk Perception &amp; Distribution</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PTC Instead of Investment-Based Grant</td>
<td>8% IRR</td>
<td>56%</td>
</tr>
<tr>
<td>No Investment-Based Grant</td>
<td>2% IRR</td>
<td>56%</td>
</tr>
<tr>
<td>No Bonus Depreciation</td>
<td>10% IRR</td>
<td>56%</td>
</tr>
<tr>
<td>No Accelerated Depreciation</td>
<td>6% IRR</td>
<td>56%</td>
</tr>
<tr>
<td><strong>Outside Investor Risk Perception</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No Term Debt Available</td>
<td>8% IRR</td>
<td>0%</td>
</tr>
<tr>
<td>Tax Benefits Carried Forward, Not Taken as generated</td>
<td>7% IRR</td>
<td>56%</td>
</tr>
</tbody>
</table>
Policy Impact Pathways

Revenue certainty
Two potential sources of revenue uncertainty for a wind project are market price expectations and production expectations. Based on ranges with a similar likelihood of occurring, market price variation presents a larger risk to equity returns. However, with the stability of a 20-year PPA, equity investors only bear the smaller production-related risks. We hope to assess the impact of this reduction of risk on the cost of capital in future work.

Risk perception
Aside from production variations, the key risks that remain with the wind project are associated with the presence of support policies, and ability to monetize tax-based incentives as they are generated (rather than carrying those benefits forward into future years).

Risk distribution
While a debt investor is exposed to moderate production risk, most of the policy-related risks fall on equity investors.

Duration
The duration of support policies for wind impacts the timing of returns for investors. For a given tax equity investment, the peak return will be realized at a different time for a tax grant and accelerated depreciation (most returns realized by year 6), versus a 10-year production tax credit and accelerated depreciation (most returns realized by year 10). The implications of these timeframes for turnover and cost of capital are an area of future study.

Completion certainty, cost certainty, development process cost & timing certainty
This analysis of a generic wind case has not address specific policy impacts on completion and cost certainty.
4.1.3 Utility Scale PV based on Greater Sandhill (U.S.)
Greater Sandhill is one of the largest PV installations to date in the U.S. The project was proposed and built in response to a request for solar energy proposals to meet Colorado’s Renewable Energy Standard’s (RES) carve out for solar. The proposal was selected as the lowest cost and most attractive proposal and awarded a long-term Power Purchase Agreement (PPA) with the Colorado utility, Public Service Company of Colorado (PSCO), for the electricity it produced at a premium to market rates. It also attracted capital from two institutional investors – MetLife and John Hancock. These investors control large amounts of capital and are often interested in time horizons close to the life of a renewable project, but until recently, have been unwilling to take on the policy and revenue risks of renewable projects in the U.S. The connection between the impacts of the PPA and the willingness of institutional investors to support the project is of interest here. We find that:

- The combined returns for all equity investors (13%) for the project are consistent with expectations (a range of 7-18.5% in Mintz Levin).
- Combined returns for all equity investors would fall below expectations if accelerated depreciation was not available (7%) or could not be monetized (7%), or no tax grant or credit was available (4%). Loss of bonus depreciation did not push returns below expectations (12%).
- The tax grant and accelerated depreciation combine to cover roughly 45% of project costs.
- The revenue support provided by the project’s PPA provides a 175% levelized premium over EIA forecasts for future market rates in Colorado. This premium can be understood as the value of a solar REC associated with the value of the project to PSCO in meeting its solar RES requirement. Loss of this premium would have made the project unviable. Loss of the support provided by PSCO’s RESA\(^5\) account would have also resulted in an unviable project.
- Greater Sandhill was awarded its PPA as the lowest cost bidder and most attractive among 23 proposed projects, 16 of which met the RFP submission criteria.
- The PPA eliminates revenue risks associated with market variability. Without the PPA (but with the premium over market rates), market prices at the lower end of expectations (one standard deviation or 24% below EIA forecasts) would drop combined equity returns to 10%.
- The solar REC premium also provides a substantial cushion for equity investors against revenue risks associated with variation in production. Even a sustained 15% drop in annual production (the lower bound for production which the PPA tolerates without penalty) reduces combined equity returns to 10%, and the equity hurdle rate for the institutional investors could still be met.
- Cost and completion risks for this project are borne by the developer, who sold the project to institutional investors at a premium only after completion.
- With both the PPA and the cost and revenue supports in place, the stable, significant revenues from the project after completion were appealing to institutional investors. Thus, these policies enabled SunPower to own and build the project as a turn-key utility-scale solar generator which they could then sell after completion to a long-term investor.

\(^5\) Colorado’s RES policy allows investor-owned utilities to collect a “Renewable Energy Standard Adjustment” or RESA charge on bills for energy consumers, not to exceed 2% of total bills. For this project, the utility PSCO estimated the impact of the Greater Sandhill project on their RESA account to be 24 $/MWh.
**Selected Sensitivities**

<table>
<thead>
<tr>
<th></th>
<th>Estimated Developer IRR</th>
<th>Estimated Outside Equity IRR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base Case</strong></td>
<td>23% IRR</td>
<td>9% IRR hurdle met</td>
<td>54% (47% actual)</td>
</tr>
</tbody>
</table>

**Revenue Support & Certainty**

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>Estimated Developer IRR</th>
<th>Estimated Outside Equity IRR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Loss of Implied Premium</td>
<td>&lt;0% IRR</td>
<td>Hurdle not met</td>
<td>17%</td>
</tr>
<tr>
<td>Loss of RESA REC Support</td>
<td>5% IRR</td>
<td>Hurdle met</td>
<td>44%</td>
</tr>
<tr>
<td>Varying Market Price Expectations without PPA</td>
<td>11% - 27% IRR</td>
<td>Hurdle met</td>
<td>49% - 59%</td>
</tr>
<tr>
<td>Varying Production Expectations with PPA</td>
<td>10% - 39% IRR</td>
<td>Hurdle met</td>
<td>46% - 63%</td>
</tr>
</tbody>
</table>

**Risk Perception & Distribution**

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>Estimated Developer IRR</th>
<th>Estimated Outside Equity IRR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td>No Investment-Based Grant</td>
<td>4% IRR</td>
<td>Hurdle not met</td>
<td>54%</td>
</tr>
<tr>
<td>No Bonus Depreciation</td>
<td>18% IRR</td>
<td>Hurdle met</td>
<td>54%</td>
</tr>
<tr>
<td>No Bonus Dep., No 5-yr MACRS</td>
<td>7% IRR</td>
<td>Hurdle not met</td>
<td>54%</td>
</tr>
<tr>
<td>Shorter PPA &amp; Debt Term (15 Yrs)</td>
<td>12% IRR</td>
<td>Hurdle met</td>
<td>47%</td>
</tr>
</tbody>
</table>

**Cost Certainty**

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>Estimated Developer IRR</th>
<th>Estimated Outside Equity IRR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Cost (± 5%)</td>
<td>20% - 29% IRR</td>
<td>Hurdle met</td>
<td>54%</td>
</tr>
</tbody>
</table>

**Completion Certainty**

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>Estimated Developer IRR</th>
<th>Estimated Outside Equity IRR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Construction Time (±1Q)</td>
<td>20% - 31% IRR</td>
<td>Hurdle met</td>
<td>54%</td>
</tr>
</tbody>
</table>

**Policy Impact Pathways**

Revenue certainty
The RES-driven PPA provides Greater Sandhill with predictable revenues at a premium to electricity market rates for a 20-year period. Long-term certainty of revenues is often cited as a key investment objective for institutional investors, and Greater Sandhill’s PPA was likely a key factor driving financial involvement of institutional investors.

Risk perception
One element of the RFP process was screening of projects for developer experience, which gave an advantage to Sun Power over other bids. The combination of a stable long-term contract for output and the transfer of some technical risks to Sun Power (as the EPC and O&M contractor) allowed for a project that appears to bear relatively little risk to operating owners and lenders.

Risk distribution
Sun Power’s turn-key approach to project development allows them to absorb construction cost and completion risks, which institutional investors might not be willing to bear. However, this business model relies on a market for low-risk, long-term assets with revenue streams from long-term contracts.

Duration
The 20-year term of the PPA matches the 20-year tenor of the debt issued by the project. A shorter PPA term could have resulted in less debt (raising the overall cost of capital), and a less attractive project from the developer standpoint.

Completion certainty
Completion certainty was not directly impacted by policy, though Colorado’s RES created a market for solar through a carve-out, and PSCO’s solar RFP specified a timeline for when solar energy would be delivered (which is reinforced in the PPA agreement).
Cost certainty
The competitive RFP bidding process and resulting PPA gave Sun Power an incentive to reduce the costs of the project, and contain those costs in order to realize their desired return on the project.

Development process cost and completion certainty
The development timing and cost may not have been directly impacted by policy, though the timing in the solar RFP likely played a role in driving the development process.
4.1.4 Solar Power Tower based on BrightSource Ivanpah

As the project is five times larger than any other solar power tower built to date, this case provides an example of how government policies can catalyze scale-up. Very few investors are willing to bear renewable scale-up risks – getting a first-of-a-kind project up and running on time and on budget, revenues which depend on the weather as well as a first-at-scale technology working all the time, and cost of electricity far above market rates leading to dependence on government incentives – and they demand a premium to do it. How did policy result in private and public investment for this project? Our key findings are:

- The combined returns for all equity investors (17%) for the project are consistent with expectations for CSP projects (a range of 15-20% in Mintz Levin).
- Combined returns for all equity investors would fall below expectations if accelerated depreciation was not available (8%) or could not be monetized through a tax equity arrangement (8%), no tax grant or credit was available (3%), no property tax exemption was provided (10%), or no DOE loan was provided (10%).
- The tax grant, accelerated depreciation, and property tax exemption combine to cover roughly 43% of levelized project costs.
- The financing structure, enabled by the loan guarantee, reduces the levelized cost by roughly 26 USD/MWh, or 13%, relative to utility financing. This is comparable to the amount set aside by the government to cover the cost of the guarantee – on average roughly 15% of loan volume, or 12% of total project costs for the loan guarantee program [Credit Supplement to the President’s Budget for 2012].
- The revenue support provided by the project’s PPAs with two California utilities provides a 50% levelized premium over EIA forecasts for future market rates in California.
- The PPA eliminates revenue risks associated with market price variability. Without the PPA (but with the premium over market rates), market prices at the lower end of expectations (one standard deviation or 24% below EIA forecasts) would drop equity returns to 10% and drop the minimum DSCR for the government loan to 1.1.
- The remaining revenue risks are not substantial, and are borne by equity investors. A sustained 3% drop in annual production (one standard deviation below expected production) reduces combined equity returns to 16%.
- Project construction, completion, and operational risks are borne by the equity investors. A loan grace period (assumed to be 2 years) as well as funded construction and debt service reserves (conditions of government debt) help shield the DOE from these risks.
- Catastrophic risks (substantial delays, excessive cost overruns, failure of a phase of the plant to operate, etc.) are socialized through the DOE loan guarantee, which would cover loan payments in the event of a default.
- Our base case assumed a PPA and loan term of 25 years.\(^6\) If we were to shorten both the PPA and the loan term to 20 years, equity returns would fall to 12%, somewhat below expectations, while an increase to 30 years would allow for 20% returns.

\(^6\) In modeling Ivanpah, we assumed the federal loan and the PPA for Ivanpah were both for 25 years. Ivanpah actually has three PPAs, one for 20 years and the other two for 25 years, and the loan could be for as long as 30 years under the rules of the loan guarantee program.
## Selected Sensitivities

<table>
<thead>
<tr>
<th></th>
<th>Estimated Equity IRR</th>
<th>Estimated Minimum DSCR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base Case</strong></td>
<td>17%</td>
<td>1.4</td>
<td></td>
</tr>
<tr>
<td><strong>Revenue Certainty</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>With PPA - Uncertain production (± 3%)</td>
<td>16%-18%</td>
<td>1.3-1.5</td>
<td></td>
</tr>
<tr>
<td>No PPA or RECs - Market Variability (± 24%)</td>
<td>0%-7%</td>
<td>0.9-1.9</td>
<td></td>
</tr>
<tr>
<td>No PPA w/ RECs - Market Variability (± 24%)</td>
<td>10%-17%</td>
<td>1.1-1.7</td>
<td></td>
</tr>
<tr>
<td><strong>Risk Perception &amp; Distribution</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No Property Tax Exemption</td>
<td>10%</td>
<td>1.4</td>
<td>64%</td>
</tr>
<tr>
<td>No Accelerated Depreciation</td>
<td>8%</td>
<td>1.4</td>
<td>67%</td>
</tr>
<tr>
<td>No Tax Grant</td>
<td>3%</td>
<td>1.4</td>
<td>54%</td>
</tr>
<tr>
<td>Best Possible Private Debt (7.5%, 1.2 DSCR)</td>
<td>10%</td>
<td>1.4</td>
<td>48%</td>
</tr>
<tr>
<td><strong>Risk Distribution</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>One tower never produces (-30%)</td>
<td>0%</td>
<td>0.9</td>
<td></td>
</tr>
<tr>
<td><strong>Duration</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shorter PPA and Debt Term (20 Years)</td>
<td>12%</td>
<td>1.4</td>
<td></td>
</tr>
<tr>
<td><strong>Completion Certainty</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Time (±4Q)</td>
<td>14%-21%</td>
<td>1.4</td>
<td></td>
</tr>
<tr>
<td><strong>Cost Certainty</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Cost (±7%)</td>
<td>14%-20%</td>
<td>1.4</td>
<td></td>
</tr>
</tbody>
</table>

## Policy Impact Pathways

### Revenue certainty
The RPS driven PPA substantially protects Ivanpah’s investors (as well as the federal government, as a debt provider) from the otherwise significant risks associated uncertainty in future electricity market prices, but at a cost to ratepayers (the implicit REC premium in the PPA). With the PPA, the primary revenue risk to investors is uncertain production due to resource intermittency or technology availability, which (as estimated by the developer and verified during regulatory oversight) is relatively much smaller than the market risk. We hope to undertake further analysis to tease out the value of this risk reduction to the relevant stakeholders (ratepayers, utilities, government, etc.).

### Risk perception
Combined equity returns would fall below expectations if any of the incentives utilized by Ivanpah were removed. This suggests that the perception of policy (and regulatory) risk associated with the failure to obtain (or retroactive repeal of) any one of them may have been a concern for investors. We hope to explore this question further in continuing case work.

### Risk distribution
Catastrophic risks to the project are shared with the Federal government through the loan guarantee. For example, in the event of a failure which leads to default of a PPA (production more than 20% below expectations) or inability to meet a regulatory deadline (such as for a permit or tax grant) the project would default on the government loan and trigger a guarantee payment by the DOE. The federal government sets aside a credit subsidy amount for each loan to cover the possibility of such a default – on average, this amount is roughly 15% of the total loan volume for this program, or 12% of total project costs. We hope to return to the question of the costs and benefits of this guarantee to various stakeholders in future work.

### Duration
The duration of the PPA and the federal loan plays a key role in enabling equity returns in line with expectations.
Cost certainty
The DOE loan guarantee and equity participation agreements require equity funding of a 3% overrun reserve and a commitment by the developer to cover any further cost increases. A fixed-price contract for the bulk of construction with a large engineering contractor in turn mitigates cost uncertainty risks to investors. Thus, the primary cost risk remaining for project investors as well as the government as a debt provider is related to the developer’s ability to honor its commitment to cover costs not related to the engineering contractor’s scope.

Development process cost & timing certainty
Since development makes up to 5% of project costs, direct policy impacts modeled as changes to development costs or timing do not significantly impact financial metrics such as equity returns. However, this approach does not capture the most interesting policy impacts through this pathway. The development process for Ivanpah was intimately tied to regulatory processes, as the project was being undertaken on federal lands and dependent upon meeting incentive deadlines (tax grant, loan guarantee, PPA) to achieve returns in line with expectations.

As the first at-scale facility of its kind, this process was complex (roughly 50 required permits from local, state, and federal regulators), and required dealing with substantial issues – for example, Ivanpah is sited on federal lands and expected to disturb a number of threatened desert tortoises equivalent to roughly 1% of its remaining population. The project itself was significantly modified (from two 100MW phases and one 200MW phase with several towers to one 126MW and two 135MW towers), the timeline for development and construction extended, and the financial structure of the project (the requirement of a roughly 20% equity stake in the project) largely determined as a result of these interactions. The uncertainty associated with such extensive regulatory and policy interactions required for this project may have impacted the availability and cost of financing for this and future projects. In future work, we hope to better assess the existence and/or extent of such impacts in this and related cases.

What will the public get for its investment in Ivanpah?
The primary quantifiable public benefit of government investment in this project is the annual generation of nearly 1 TWh of solar electricity without significant emissions. However, this project costs significantly more than other low-emissions generation options such as wind. Thus, public support of Ivanpah is predicated on benefits other than direct emissions reduction – here, the hope that scale-up of a promising technology will lead to learning by doing and economies of scale which will reduce future costs. In addition, successful operation of Ivanpah can reduce perceived operational risks for future projects and the premiums charged by investors to bear such risks, thereby also lowering their costs. However, failure of this project, particularly given the high fraction of public support, can result in significant political risks to the success of future renewable policy efforts. Thus, from the point of view of government as well as the private sector, this is a high risk, high return investment.
4.2 European Cases and Policies

Generic Spanish Wind based on Villanueva (Spain)
The Elecnor Villanueva wind farm is a 66.7 MW project near Valencia, Spain. The project was commissioned in November 2009. The key support provided to this project came in the form of a feed-in premium for wind projects. Spain allows wind projects to receive a 29.2 EUR / MWh feed-in premium (adjusted annually for inflation) above market rates, adjusted such that the sum of the premium and market rates falls with an inflation adjusted price collar between 71.3 - 84.9 EUR / MWh. This incentive scheme is revisited every four years, and can be adjusted to meet target project IRRs of 5-9%. Key policy impact questions here include the impact of the market price risk that the feed-in premium leaves on investors (and how that market price risk differs with incentive design), as well as the impact of policy uncertainty.

Utility Scale Solar PV based on Rovigo (Italy)
The Rovigo solar PV plant was commissioned in Northern Italy in December 2010. Boasting a 70 MW DC capacity, the EUR 320 million PV plant was the largest single operating PV system in Europe at its completion date. The PV system was completed, interconnected and commissioned in nine months. The project benefited from a:

- Feed-in premium of EUR 346/MWh fixed for 20 years (without any inflation adjustment) for solar PV
- Guaranteed offtake of electricity at market rates for 20 years
- A reduced VAT rate (10% instead of 20%) for construction costs.
- Priority dispatch
- One-stop shop for permitting

In the spring of 2010, major uncertainty surrounded the future of feed-in premia in Italy beyond 2010. To benefit from the higher premium, the developer completed the large scale plant in less than 9 months. Feed-in premia are funded by all Italian ratepayers via a specific cost component on the bill. Key policy impact questions here are focused on the rush to complete the project in due time to be awarded the generous premium, the level of the feed-in premium and the sustainability thereof.

Offshore Wind based on Anholt (Denmark)
Anholt, when completed in 2013, will be a 400 MW off-shore wind farm, the largest so far to be built off the coast of Denmark. It benefits from a Feed-in-Tariff for its first 20 TWh of production (roughly 13 years), and is the first large offshore wind farm to attract pre-completion commitment to financing from institutional investors (two Danish pension funds). Key questions here are focused on what policy features made institutional investors comfortable with investing in this project which has relatively high costs and revenues which depend on policy stability.
European Case Results

- **Returns**: With the exception of Rovigo, equity returns for projects are in line with expected ranges. While Rovigo’s returns are only slightly higher than McKinsey’s estimates for returns on Italian PV projects, they are substantially higher than PV projects in neighboring countries.

- **Cost and revenue support mechanisms**: Higher electricity prices in Europe somewhat reduce the required revenue support. To some extent, these higher prices are themselves a reflection of policy, including the EU ETS. In contrast to the U.S., European projects rely primarily on a single revenue support policy – either a FiT or a FiP – which provides between 25-75% of levelized project revenues.

- **Revenue certainty**: FiT and FiP policies significantly mitigate risks associated with uncertain revenues or market prices. Of the two, FiT offer investors greater certainty, with FiP leaving the investor with some risk related to underlying commodity price fluctuations. The impact on financing costs of leaving commodity price risk with investors (and the value to government of transferring that risk to investors) is an area for further investigation. We note, however, that one result of leaving that risk to developers is to create a comparative advantage for developers who can manage the commodity risks or have offsetting risks, such as large incumbent utilities. The effect of creating this advantage is also an important area for further work.

- **Risk distribution – Mezzanine investors**: The significant and stable revenues afforded by these policies can also enable equity participation by institutional investors, if project sponsors are willing to insulate them from completion and policy risks.

- **Risk distribution – Government**: Setting the right price for a FiT or FiP is a politically risky decision which is not stable under changing market conditions. If the price is too high, the rush to cash in on the incentive can lead to increasing high costs and returns. If it’s too low, projects will not find investors willing to take on project risks given the possible returns.

- **Risk perceptions**: The substantial size of revenue support required to render a solar project viable can lead to policy uncertainty and increased perceptions of regulatory or policy risks which can increase financing costs. We note that in response to problems setting FiT, government have been forced to change policies, and in some cases change tariffs retroactively. Numerous interviewees expressed concern over heightened risk and lack of future investability, although this view was not universally shared. The impact of these changes will be an area of CPI investigation as time progresses and the full impact can be observed.

- **Other Impact pathways**: Policy and regulation vary significantly across the continent. Investors expressed the opinion that the duration of policy support and the certainty of items such as cost (which were affected by policy structure and contractual arrangements, as in the case of Anholt) and support duration had some impact on the price for which the sponsor was willing to build the project.
### 4.2.1 Key Modeling Assumptions

<table>
<thead>
<tr>
<th></th>
<th>Generic Spanish Wind based on Villanueva</th>
<th>Utility Scale PV based on Rovigo</th>
<th>Offshore Wind based on Anholt</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Project Size</strong></td>
<td>66.7 MW AC</td>
<td>60 MW AC</td>
<td>400 MW AC</td>
</tr>
<tr>
<td><strong>Production</strong></td>
<td>146,000 MWh / Yr</td>
<td>88,500 MWh / Yr</td>
<td>1,400,000 MWh / Yr</td>
</tr>
<tr>
<td><strong>Project Cost</strong></td>
<td>124m EUR</td>
<td>320m EUR</td>
<td>9.3b DKK (1.4b EUR)</td>
</tr>
<tr>
<td><strong>First-Year FiP Rate</strong></td>
<td>31.3 EUR / MWh</td>
<td>346 EUR / MWh</td>
<td></td>
</tr>
<tr>
<td><strong>First-Year FIT Rate</strong></td>
<td>-</td>
<td>-</td>
<td>1,015 DKK (154 EUR) / MWh</td>
</tr>
<tr>
<td><strong>FiP or FIT Duration</strong></td>
<td>20 Years</td>
<td>20 Years</td>
<td>For 20 TWh of electricity</td>
</tr>
<tr>
<td><strong>First-Year Market Rates</strong></td>
<td>50 EUR / MWh</td>
<td>70 EUR / MWh</td>
<td>340 DKK (50 EUR) / MWh</td>
</tr>
<tr>
<td><strong>Fixed O&amp;M</strong></td>
<td>29 EUR / kW-Year</td>
<td>22 EUR / kW-Year</td>
<td>670 DKK (98 EUR) / kW-Year</td>
</tr>
<tr>
<td><strong>Base Case Term Debt</strong></td>
<td>77m EUR</td>
<td>240m USD</td>
<td></td>
</tr>
<tr>
<td><strong>Base Case VAT Facility</strong></td>
<td>14m EUR</td>
<td>38m USD</td>
<td></td>
</tr>
<tr>
<td><strong>Required Min DSCR</strong></td>
<td>1.4x</td>
<td>1.4x</td>
<td></td>
</tr>
<tr>
<td><strong>Debt Interest Rate</strong></td>
<td>5.08%</td>
<td>6.48-6.98%</td>
<td>-</td>
</tr>
<tr>
<td><strong>Outside Equity Hurdle</strong></td>
<td>-</td>
<td>15%</td>
<td>8%</td>
</tr>
<tr>
<td><strong>LCOE Discount Rate</strong></td>
<td>8.00%</td>
<td>8.00%</td>
<td>8.00%</td>
</tr>
</tbody>
</table>

**Sources:**


Rovigo: SunEdison, First Reserve, Partners Group, MEMC SEC Filings, Vento Region (EIS), GSE, GME, IEA, Andromeda Finance, Bloomberg, Project Finance Magazine, RES Legal, BNEF.

4.2.2 Levelized Cost and Revenue Comparison

Using the methods described above for the U.S. cases, we calculated levelized costs and revenues for each of the European cases, presented below in USD. Several preliminary observations emerge from this calculation.

- The primary form of support for European projects has been on the revenue side, through feed-in premia and feed-in tariffs. These incentives are atop (or in place of) market prices for electricity that are generally higher than for our U.S. cases.
- The financial structure of European projects is relatively close to the assumed utility cost of capital.
- Overall project costs for the Utility Scale PV, based on Rovigo, appears to be much higher than the U.S. Utility Scale PV case, and generally on the high end of levelized cost estimates for PV plants. This could be driven by a lack of incentive to reduce project costs, because high returns were available to investors in Italian PV, even after high project costs.

Note that the basis for market prices forecasts are: national power markets data and simple linear growth rate for Spain, two-stage growth for Italy, and a specific "official" price path projection for Denmark

Figure 4 – Levelized Costs and Revenues for Generic Spanish Wind based on Villanueva
Figure 5 – Levelized Costs and Revenues for Utility Scale PV based on Rovigo

- Counterfactual LCOE: 408 USD/MWh
- Tax Credits and Grant: -
- Property Tax Concessions: -
- Sales / VAT Tax Concessions: -
- Depreciation Tax Benefits: -
- LCOE After Tax Benefits and Grant: 400 USD/MWh
- Financial Structure and Reserves: 8 USD/MWh
- Final LCOE after Financing: 408 USD/MWh
- Final After-Tax Levelized Revenues: 408 USD/MWh
- Cash Incentive or Premium: 296 USD/MWh
- REC Revenue: -
- Incremental PPA or Tariff Revenue: -
- After-Tax Revenues at Market Rates: 112 USD/MWh

Levelized Costs and Revenues (USD/MWh)

Figure 6 – Levelized Costs and Revenues for Offshore Wind based on Anholt

- Counterfactual LCOE: 152 USD/MWh
- Tax Credits and Grant: -
- Property Tax Concessions: -
- Sales / VAT Tax Concessions: -
- Depreciation Tax Benefits: -
- LCOE After Tax Benefits and Grant: 152 USD/MWh
- Financial Structure and Reserves: 7 USD/MWh
- Final LCOE after Financing: 159 USD/MWh
- Final After-Tax Levelized Revenues: 159 USD/MWh
- Cash Incentive or Premium: -
- REC Revenue: -
- Incremental PPA or Tariff Revenue: -
- After-Tax Revenues at Market Rates: 90 USD/MWh

Levelized Costs and Revenues (USD/MWh)
4.2.3 Generic Spanish Wind based on Villanueva (Spain)

Our generic wind case based on the Villanueva project (built as two phases, on 48.3 MW and the other 18.4 MW) demonstrates the impact of the Spanish wind incentives. Spain allows projects less than 50 MW to receive a 29.2 EUR / MWh feed-in premium (adjusted annually for inflation) above market rates, adjusted such that the sum of the premium and market rates falls with an inflation adjusted price collar between 71.3 - 84.9 EUR / MWh. These projects can also choose between this premium and (an inflation adjusted) feed-in tariff of 73.2 EUR / MWh for 20 years, dropping to 61.2 EUR / MWh thereafter. For our Spanish generic wind case, we find that:

- Equity returns (11%) are generally consistent with estimates for levered IRR’s from Macquarie.
- Equity returns would fall below expectations if the feed-in premium were removed (4% IRR) or reduced by 75% (5% IRR). However, a smaller reduction in the premium might still allow for equity IRRs within expected ranges.
- The feed-in premium, borne by Spanish ratepayers, constitutes 25% of levelized revenues for this Spanish wind case, with the remaining 75% from forecast market prices from [SOURCE – Morgan?].
- The price collar that accompanies Spain’s feed-in premium limits the impact of market price risks, and protects ratepayers from higher than expected market prices for electricity. The feed-in tariff option eliminates this price risk for investors.
- The market price risk exposure that is left with investors with a feed-in-premium does not significantly impact project viability.

Selected Sensitivities

<table>
<thead>
<tr>
<th></th>
<th>Equity IRR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base Case</strong></td>
<td>11% IRR (9% actual)</td>
<td>77% (62% actual)</td>
</tr>
<tr>
<td><strong>Revenue Support</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>No Feed-in Premium</td>
<td>4% IRR</td>
<td>38%</td>
</tr>
<tr>
<td>No Price Collar</td>
<td>11% IRR</td>
<td>77%</td>
</tr>
<tr>
<td>Feed-in Tariff</td>
<td>11% IRR</td>
<td>76%</td>
</tr>
<tr>
<td><strong>Revenue Certainty</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market Price Expectations (±24.5%)</td>
<td>7% - 12% IRR</td>
<td>66% - 82%</td>
</tr>
<tr>
<td>- Without Price Collar</td>
<td>7% - 16% IRR</td>
<td>62% - 84%</td>
</tr>
<tr>
<td>- With Feed-in Tariff</td>
<td>11% IRR</td>
<td>76%</td>
</tr>
<tr>
<td>Production Expectations (±5%)</td>
<td>9% - 12% IRR</td>
<td>72% - 82%</td>
</tr>
<tr>
<td><strong>Risk Perception</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Premium Reduced 25%</td>
<td>8% IRR</td>
<td>67%</td>
</tr>
<tr>
<td>Premium Reduced 50%</td>
<td>6% IRR</td>
<td>57%</td>
</tr>
<tr>
<td>Premium Reduced 75%</td>
<td>5% IRR</td>
<td>48%</td>
</tr>
<tr>
<td>No Feed-in Premium</td>
<td>4% IRR</td>
<td>38%</td>
</tr>
</tbody>
</table>

Policy Impact Pathways

Revenue certainty

One quarter of levelized revenues are provided by the feed-in premium, while three quarters are derived from less predictable power market sales. However, the Spanish feed-in premium policy includes a price collar, which creates additional revenue certainty for investors and protects consumers from the cost of a premium over higher-than expected prices. The feed-in tariff option, available to projects less than 50 MW, eliminates market price risk for wind projects.
Risk perception
In the past Spain has experienced policy oversubscription (particularly with the PV feed-in tariff) and reacted by imposing retroactive tariff cuts. The current wind support scheme includes review periods every 4 years. The extent to which these factors increase the perception of policy risk among investors is an interesting area for further study.

Risk distribution
Most project risks, aside from policy risks associated with removal of support, are borne by project equity investors. A significant amount of debt can be supported by the project, even with variations in production and market prices.

Duration
The 20-year duration of the premium matches the 20-year tenor of the debt offered to the project. The impact of this duration on availability and cost of capital would be an area for future study.

Completion certainty, cost certainty, development process cost & timing certainty
This analysis of a generic wind case has not address specific policy impacts on completion and cost certainty.
4.2.4 Utility Scale Solar PV based on Rovigo (Italy)

Rovigo is one of the largest utility-scale solar photovoltaic (PV) installations in Europe, and is being built largely as a result of revenue support through a substantial feed-in-premium (FiP) intended to catalyze solar development. The size of the premium – EUR 346/MWh, a 5:1 premium over local grid prices and higher than neighboring countries’ support schemes (between EUR 135-320/MWh) – attracted overwhelming interest in Italy for PV installations in 2010. As a result, projections for the cost of the premium exploded far beyond expectations. This, in turn, created political pressure which led to significant, retroactive downward adjustments in the premiums offered based upon the date of final completion of the projects – down to 297 EUR/MWh in the Spring of 2011 and then ramping down to 172 EUR/MWh by December. We explore the impacts of the Italian premium and its recent history on the project and its financing structure. Our findings are:

- Equity returns (27%) are higher than estimates from Solar Energy Partners (15%-18%) for all of Europe.
- According to McKinsey data, this is only slightly higher than typical returns for PV in Italy (26%).

<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Stuttgart, Germany</td>
<td>6-8%</td>
</tr>
<tr>
<td>Seville, Spain</td>
<td>21%</td>
</tr>
<tr>
<td>Palermo, Italy</td>
<td>17-26%</td>
</tr>
<tr>
<td>Nice, France</td>
<td>3-13%</td>
</tr>
<tr>
<td>Athens, Greece</td>
<td>17-23%</td>
</tr>
</tbody>
</table>


- Equity returns would fall below expectations if the FiP level were reduced to the level available in June (264 EUR/MWh – 13%), September (231 EUR/MWh - 7%) or December of 2011 (172 EUR/MWh – 0%). However, the levels in March (297 EUR/MWh – 19%) still allow for returns within expected range. Removal of the VAT subsidy still allows robust equity returns (23%).
- The FiP provides 72% of the levelized revenues to the project over a 20 year period, a 265% premium over forecasted market rates from [SOURCE – Morgan?]. The cost of the FiP is borne by Italian ratepayers.
- The VAT subsidy covers 2% of levelized project costs.
- The market price risk exposure that is left with investors with the FiP does not significantly impact project viability (returns between 21%-31%).
- The high premium also provides a substantial cushion for equity investors against revenue risks associated with variation in production and cost risks associated with overruns. Even a sustained 15% drop in annual production reduces combined equity returns to 16%, while a 10% increase in construction costs reduces returns to 15%.
- Rovigo’s levelized cost of electricity ($408 / MWh) is very high (more than double that of Greater Sandhill - $184 / MWh), and may reflect the impact of supply constraints associated with the rush to qualify for Italy’s premium in 2010. The fact that four different module suppliers were utilized at Rovigo also supports this hypothesis.
Selected Sensitivities

<table>
<thead>
<tr>
<th></th>
<th>Equity IRR</th>
<th>Potential Leverage</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base Case</strong></td>
<td>27%</td>
<td>94% (90% actual)</td>
</tr>
</tbody>
</table>

**Revenue Certainty**
- Market Price Expectations (± 24%) 21%-31% 86% - 95%
- Production Expectations (± 15%) 16%-37% 80% - 95%

**Risk Perception**
- Loss of VAT Exemption 23% 95%
- Constant 265 bp spread 27% 95%

**Duration**
- FiP and Loan Term of 15 Years 15% 85%

**Cost Certainty**
- Construction Costs (± 10%) 15%-66% 90%-95%

**Completion Certainty**
- Delayed 1Q (EUR 297 / MWh FiP) 19% 92%
- Delayed 2Q (EUR 264 / MWh FiP) 13% 90%
- Delayed 3Q (EUR 231 / MWh FiP) 7% 83%
- Delayed 4Q (EUR 172 / MWh FiP) 0% 69%

**Policy Impact Pathways**

Revenue certainty
Close to 80% of the total revenues of the Rovigo PV system are supported by a EUR 346/MWh feed-in premium over 20-years, providing significant revenue certainty. The remaining 20% of revenues are exposed to market prices. However, the _ritiro dedicato_ between the PV producer (SunEdison) and the Italian agency managing the feed-in premium system removes quantity risk by guaranteeing offtake for the electricity at market-related prices. Note that even rather significant variations in production expectations do not render the project unviable.

Risk perception
The strong decrease in the Italian FiP level starting early in 2011 triggered concerns in 2010 among investors that Terna, the main Italian grid operator, would not be able to cope with the rush to benefit from the more interesting FiP. Policymakers reacted with the Salva Alcoa law and subsequent legislation that changed the award criteria to having the PV system built and having requested Terna connection to the grid before December 2010 and entering into operations by June 30th 2011. One piece of evidence for the hypothesis that the perception of policy risk associated with this coming decrease still may have led to increasing costs is that the debt structure of Rovigo features an increasing margin charged against EURIBOR rate (265 bps for 6 years, 290 bps for 6 years and 315 bps for the remaining 6 years). This gives the borrower the incentive to refinance at some point – allowing the lender to reduce its exposure to such perceived risks. We note, however, that the increasing spread has a very small impact on equity returns overall, and that transaction costs may overwhelm this incentive.

Risk distribution
Overall, the high level of the Italian FiP mitigates the downside risks to equity investors, by shifting costs to ratepayers more broadly.

Duration
The 20-year duration of the Italian FiP played an important role in enabling equity investors to achieve high returns by levering their investment with long-term debt of roughly the same duration (18 years). A reduction to a 15 year FiP and loan term significantly reduces the achievable leverage and potential equity returns.
**Cost certainty**
The high tariff level provided project developers substantial incentive to increase returns by reducing costs. However, as many developers rushed to complete projects in time to qualify for the high tariff rate by the end of the year, supply constraints likely made cost containment very challenging. In the case of Rovigo, this is evidenced by the very high levelized cost of electricity relative to Greater Sandhill.

**Completion certainty**
The FiP which Rovigo received in Italy was scaled back substantially for projects completed in 2011: from EUR 297/MWh in early 2011 (-14%) to EUR 172/MWh at the end of 2011 (-50%) – returns for Rovigo itself (keeping costs fixed) would have been significantly impaired if delays had pushed its completion towards the second half of 2011.

**Development process cost & timing certainty**
Italy’s one-stop shop for permitting was intended to address development cost & timing risks – in future work we hope to compare the impact of streamlined permitting to regimes without such efforts.
4.2.5 Offshore Wind based on Anholt (Denmark)

Anholt will be the largest wind farm off the shore of Denmark and is being built by DONG Energy, a Danish integrated energy company. The majority of revenue for this project is dependent on policy, a Feed-in-Tariff (FiT) of DKK 1.051 / kWh for the first 20 TWh of production (roughly 13 years). It is also the first such facility to attract an equity investment commitment from pension fund investors prior to completion, and we are interested in the conditions which made this possible. We find that:

- Equity returns (10% DONG, 8% Pension Fund) are consistent with estimates for unlevered returns equity from KPMG (4%-13%).
- Equity returns would fall below expectations if the FiT was removed (2% DONG, 2% Pension Fund), but remain within expectations for variations within a range of reasonable tariffs identified by an outside review of DONG’s proposal (8%-14%).
- The FiT provides 71% of the project’s levelized revenues over a 20 year period, an effective 77% premium over levelized revenues at forecasted market rates. The cost of the FiP is borne by Danish ratepayers.
- Anholt’s FiT provides greater revenue certainty than a FiP, providing equity returns that are stable (variations of 1-2%) under even fairly significant variations in production expectations and market conditions.
- The Danish Energy Agency has set strong penalties in case the offshore farm is not built in due time: reduction in tariff, increasing penalties with greater delays, etc. Through a performance guarantee, DONG Energy bears these risks rather than the pension funds. However, equity returns are also not significantly impacted by these penalties and reductions.
- Only a loss of the FiT entirely results in a substantial impairment of investor returns. This risk is also borne by DONG Energy.
- The combination of fairly stable returns under operational risks due to the FiT with a sponsor guarantee bearing completion and policy risks gave rise to conditions amenable to investment by two pension funds.

**Selected Sensitivities**

<table>
<thead>
<tr>
<th></th>
<th>Estimated DONG Energy IRR</th>
<th>Estimated Pension Funds IRR</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Base Case</strong></td>
<td>10%</td>
<td>8%</td>
</tr>
<tr>
<td><strong>Revenue Certainty</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Market Price Expectations (± 24%)</td>
<td>9% - 10%</td>
<td>8% - 9%</td>
</tr>
<tr>
<td>Production Expectations (± 15%)</td>
<td>8% - 11%</td>
<td>7% - 9%</td>
</tr>
<tr>
<td>Production Expectations (-30%)</td>
<td>7%</td>
<td>6%</td>
</tr>
<tr>
<td><strong>Risk Perception</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Variation of FiT (DKK 0.993-1.184 / kWh)</td>
<td>8-14%</td>
<td>8%</td>
</tr>
<tr>
<td>Loss of FiT</td>
<td>2%</td>
<td></td>
</tr>
<tr>
<td><strong>Duration</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>13 Year FiT rather than for 20 TWh</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td><strong>Completion Certainty</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Interconnection Delay of 1Q</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td>Interconnection Delay of 2Q</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td>Interconnection Delay of 3Q</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td>Interconnection Delay of 4Q</td>
<td>7%</td>
<td>8%</td>
</tr>
<tr>
<td><strong>Cost Certainty</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Construction Cost (+30%)</td>
<td>3%</td>
<td>8%</td>
</tr>
</tbody>
</table>
Policy Impact Pathways

Revenue certainty
The FiT provides a fixed price for the first 20TWh produced, which provides greater revenue certainty than a FiP, as the investor does not have any market price risk to manage until the FiT expires. After the expiration, the operator must manage electricity market price risk again through some mechanism, but these risks do not substantially impair overall return expectations. Technology availability and lower than expected actual wind resources can lead to lower production expectations, but returns are not significantly impaired except in the case of long-term, significant lack of availability.

Risk perception
Variation of the FiT consistent with independent assessments of a fair tariff range (roughly DKK 0.993 – 1.184 / kWh as identified by a study commissioned by the Danish Energy Agency to assess DONG’s bid on the tender for the Anholt wind concession) does not significantly impair investor returns. A total loss of the FiT can make the project unviable, thereby potentially creating a perception of risk associated with the dependence on policy.

Risk distribution
DONG Energy arranged equity participation from pension funds by taking on the completion and policy risks and thereby shifting the initial risk allocation towards an acceptable one for institutional investors. Pension fund equity investors will generally only invest in a transaction after completion because they do not want to be exposed to that risk. Nevertheless, the transaction costs for the pension funds’ 50% stake incorporate a premium reflecting risks that remained with DONG Energy (and hence the higher return for DONG in the base case).

Duration
Anholt has a FiT for a fixed amount produced rather than over a fixed term. An interesting question to ask here is related to the impact of this tariff structure on the operator. For a fixed term tariff, the operator is motivated to produce as much renewable energy as fast as possible, while for a tariff available for a fixed amount of production, the operator may instead be motivated to optimize production based on expected future market prices. We plan on addressing this trade-off and its impact in follow-up work.

Completion certainty
Completion risks are borne by DONG Energy and do not significantly impair their returns except in the case of a full year delay. In this case, completion risks are associated with provisions in the FiT contract which require interconnection and operation of all turbines by the end of 2013, with penalties of up to a total of a DKK 0.03 / kWh decrease in the FiT and a fine of DKK 400m for noncompliance with the 2013 deadline.

Cost certainty
A substantial increase in expected construction costs can also significantly impair DONG Energy’s returns, but can still support the institutional investor’s returns.

Development process cost & timing certainty
No significant policy impacts through this pathway were analyzed.
So what does this tell us about renewable policy effectiveness?

Comparing our key findings from U.S. and European cases, we observe that:

- **With the exception of Rovigo, financing and project costs do not show evidence of overpayment.** Equity returns, debt spreads, and project costs in each case are in line with expectations based upon recent surveys and cost assumptions such as those used by EIA for its Annual Energy Outlook.

- **Rovigo shows some evidence of higher costs associated with a rush to secure a high FiP by the end of 2010.** Base case equity returns for Rovigo are above expectations and the levelized cost of electricity is double that of Greater Sandhill. Both returns and costs appear to have risen because of the high incentive level, perhaps in part due to supply pressures associated with the rush to take advantage of the incentive before it began to be wound down in 2011.

- **Institutional investors have shown a willingness to support renewable investments given revenue certainty from policy and arrangements to insulate them from completion and policy risks.** The significant and stable revenues afforded by FiTs / FiPs / PPAs enable equity returns that meet the requirements of institutional investors. However, these investments are predicated on finding partners who are willing to insulate them from completion and policy risks. Further, the institutional investors who have invested in our cases each have dedicated teams focused on renewable investments, rather than relying on outside expertise.

- **All the projects still rely on cost or revenue supports to provide revenues commensurate with the risks borne by investors.** None of the projects would have been able to provide equity investors returns commensurate to the risks borne without revenue or cost incentives. However, reductions in some incentives would still have provided adequate returns in some cases. For example, Rovigo would have easily been viable with a reduced incentive, and may have been deployed at lower cost if not for a rush to grab the high premium. On the other hand, for a scale-up project like Ivanpah, low-cost government debt enabled equity returns, while absorbing some of risk of project failure. This alignment of risk and return attracted equity investors to the project.

- **Policies such as FiT, FiP, or an RPS mitigate or eliminate market risks which would otherwise be the dominant source of revenue uncertainty.** In most of our cases, variability of future expected market prices would have been a larger source of revenue uncertainty than expected variability of the renewable resource or technology availability. Thus, revenue support policies which mitigate or eliminate these risks significantly increase revenue certainty.

- **Policy duration plays an important role in determining the mix of financing available to a project.** The duration of the revenue support policy is closely linked with the duration and type of financing a project was able to obtain – long term revenue support measures were correlated with long-term financing instruments of a comparable tenor. As leveraging with longer-term financing enables other investors to obtain higher overall returns, a longer duration of support can open up the financing possibilities available to a given project.

- **U.S. projects make use of multiple, smaller incentives, each with their own political and regulatory risks while European projects generally rely on a single larger incentive with more focused political and regulatory risks.** Each of the U.S. projects relied on simultaneously receiving multiple, smaller incentives, each of which presented unique political and regulatory
hurdles. On the other hand, each of the European projects generally relied on a single, larger incentive, thereby potentially focusing political risk on the fate of a single, more visible policy. In view of the significant pressure at all levels of government in the U.S. and Europe to reduce spending, we hope to return to the issue of how this difference in political risk structure influences investors’ perceptions of political risk – and the premium they require to bear such risk – in future work.

Based upon these findings, we identified the following key questions for follow-up work:

- **What are the key policy impact pathways most relevant to each class of investor?**

- **Can we quantify a reduction in the cost of financing or other benefits to stakeholders associated with the increased revenue certainty provided by FiT, FiP, and PPAs? Is this commensurate to the cost of providing such certainty?**

- **Do differences in policy support structures and the corresponding political risks between the U.S. and Europe influence risk perceptions and ultimately financing costs?**

Our analysis was primarily focused on impacts at the project level, but many key impacts of policy on investor decision making ultimately operate in the context of the full portfolio of investment choices already made or under consideration. How do the policy impacts we have identified at the project level roll up to change investor capital allocation decisions and either bring in new capital or create barriers to such activities? Ultimately, these decisions are critical to diagnosing why a policy does or does not result in realizing its goals. These issues are beyond the scope of the present work, but will be a focus of future work at CPI.
References

Background Materials


Bolinger, M.; Wiser, R.; Cory, K.; James, T. 2009. PTC, ITC, or Cash Grant? LBNL, NREL.


Standard & Poor’s Ratings Direct. 2006. *A Look At U.S. Wind Project Risks In A Time Of Growth*. Credit FAQ.


**Case Study Background and Details**

*Generic U.S. Wind*


*Greater Sandhill*

Greater Sandhill I, LLC, FERC Form 556, December 2010.
Direct Testimony and Exhibits of Kent Scholl, Colorado PUC Docket No. 09A-253E, April 7, 2009 (PPA Attached)


Ivanpah


Generic Spanish Wind


Rovigo


Andromeda Finance S.r.l. (2010). € 97,600,000 Class A1 5.715 per cent. Fixed Rate Notes due 2028 € 97,600,000 Class A2 4.839 per cent. Fixed Rate Notes due 2028. Prospectus.

Anholt


PensionDanmark, Selected Press Releases

PKA, Selected Press Releases


Data Sources and Modeling Reference

Bloomberg Terminal.


IMF Inflation Forecasts.


DSIRE Incentive Database, http://www.dsireusa.org/incentives/.


National Renewable Energy Laboratory, System Advisor Model (SAM).


Appendix A - Case Study Methodology and Financial model

A.1 Case Selection
CPI selected projects to study for this work guided by the following criteria:

Technology and geographic coverage
At least one case was selected in each region which involves a mature renewable technology (on-shore wind), an emerging renewable (solar photovoltaic), and a developing renewable technology (solar thermal electricity generation in the U.S. or off-shore wind in Europe).

Policy Interest
The projects chosen were tailored to enable the analysis of policies which had been identified by policymakers or other key stakeholders to be of interest (such as FITs and FiPs in Europe or loan guarantee and tax grants / credits in the U.S.).

Availability of project financial and technical data and cooperation of case stakeholders
The public availability of information regarding the financing arrangements and basic technical features of the project and the cooperation of case stakeholders was a necessary condition to case selection. The resulting selection bias can impact the extent to which conclusions motivated by this analysis can be generalized without further study.

Diversity of types and sources of financing
The cases were also chosen to attempt coverage of the range of financial sources (debt, equity, mezzanine, venture capital) and the types of financing available, but with a view towards projects employing project finance structures with some long-term debt.

Stage of Completion
Projects must have closed their financing and were ideally either in construction or in operation
A.2 Financial Model

The primary analytical tool used in this analysis is a project cash flow model, which CPI developed to examine policy impacts on key financial metrics. The model requires a range of inputs, which describe project cost, revenue, policy and financing characteristics. These inputs are used to calculate cash flows over the development, construction, and operational life of a project. Using these cash flows the model calculates a project internal rate of return (IRR), debt service coverage and whether debt is fully repaid, and returns of project equity investors, as well as the contribution to levelized costs or revenues of each policy. The types of inputs used and outputs generated by the model are described in more detail below.

<table>
<thead>
<tr>
<th>Model Inputs</th>
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<tr>
<td>• Project characteristics such as project capacity, capacity factor, and length and timing of development, construction and operations periods;</td>
</tr>
<tr>
<td>• <strong>Capital expenses and investment-based incentives</strong>, including project costs during development and construction, investment-based incentives (grants or tax credits), sales tax or value-added tax (VAT) on capital expenditures;</td>
</tr>
<tr>
<td>• <strong>Operating revenue and production-based incentives</strong>, including power purchase agreement (PPA) or tariff rate and duration, underlying market prices, renewable energy certificates (RECs), production-based incentives, production tax credits, and recovery of VAT from energy sales;</td>
</tr>
<tr>
<td>• <strong>Operating expenses</strong>, such as property taxes and concessions, annual expenses, and fixed or variable O&amp;M;</td>
</tr>
<tr>
<td>• Tax and depreciation inputs, such as national and local tax rates, depreciation schedules, bonus depreciation;</td>
</tr>
<tr>
<td>• <strong>Reserve accounts</strong> including reserves for construction cost overrun, senior debt service, major equipment replacement, O&amp;M and working capital, and PPA performance security; and</td>
</tr>
<tr>
<td>• <strong>Financing</strong>, with inputs for construction debt, senior term debt and subordinate debt (with choices in amortization method), outside equity investors, and project developers.</td>
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<table>
<thead>
<tr>
<th>Model Outputs</th>
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<tr>
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<tr>
<td>• <strong>Project metrics</strong> including project IRR, and levelized cost of energy (LCOE) before and after incentives and financing;</td>
</tr>
<tr>
<td>• <strong>Debt investor metrics</strong> including debt service coverage ratio, proportion of debt repaid;</td>
</tr>
<tr>
<td>• <strong>Equity investor metrics</strong>, particularly IRRs for developer, outside and combined equity investors.</td>
</tr>
</tbody>
</table>

**Key Modeling Assumptions**

CPI’s project cash flow model uses a range of assumptions about the categorization and nature of certain cash flows. These can broadly be categorized as assumptions about the “waterfall” of cash flows, assumptions about tax and depreciation treatment, and assumptions about capitalization vs. expensing of various costs.

**Waterfall assumptions:** The priority of various claims on the cash flows of a project is often referred to as the “waterfall” of project cash flows. CPI’s model assumes that project cash flows are first used to cover operating expenses, then to service senior debt, followed by subordinate debt service, with the remaining cash flows split between outside and developer equity investors in proportion to their contributions (or in a pre-determined fashion as is sometimes the case in tax-equity arrangements in the US).

**Tax and depreciation treatment:** CPI’s model assumes that capitalized costs, including interest paid during construction, lenders fees, and sales tax or VAT on development and construction expenditures
are depreciated over a specified schedule. Costs associated with creating reserve accounts are excluded from the depreciable basis of the project, and the option is available to reduce the depreciable basis based on investment-based incentives. Depreciation expenses, as well as interest expenses during operation, are deducted from the project’s taxable income, which in some cases yields net tax benefits.

**Capitalization vs. expensing of costs:** The model also assumes that costs incurred during development and construction of the project can be capitalized, thereby impacting the investment required by the project, as well as the amount that can be depreciated for tax purposes. In addition to hard development and construction expenditures, capitalized costs include interest paid during construction, lenders fees, and sales tax or VAT on development and construction expenditures. Costs that occur during project operation are counted against project revenues, as expenses. These costs include property taxes, annual, fixed and variable O&M costs, and fuel costs (if applicable).

**Data**
Data was collected for each case study from a range of sources, as detailed in our References. Subscription services such as Bloomberg, Bloomberg New Energy Finance, and Project Finance Magazine were used for information about financial structure, and where available, terms of financing. Regulatory filings were typically used to fill in additional details about the project, its costs and financial terms. For US projects, we drew upon regulatory filings with the Securities and Exchange Commission (SEC), Federal Energy Regulatory Commission (FERC), Bureau of Land Management (BLM) and various state environmental and utility regulators. In Europe, regulatory sources included Gestore Servizi Energetici (GSE), Gestore dei Mercati Energetici (GME), and the Danish Energy Agency.

When possible, our team tested available data and modeling assumptions through conversations with stakeholders involved in financing renewable energy projects, including several of the cases presented here.

Where a particular modeling input was not available, we developed a reasonable proxy for the missing data, based on guidelines produced by regulators, market data, or assumptions from other industry models.