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The geography of project finance in U.S. electricity generation[☆]

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ABSTRACT

Technology costs, state and federal policies and incentives, and local factors such as construction costs and prevailing electricity prices interact to determine the economic favorability of a generation technology in a particular place. To disentangle these factors and better understand how federal policies can make new generation economically viable, we present an integrated multi-technology, state-level project finance model called the Project Finance Mapping Tool and apply it to a variety of policy scenarios.

1. Introduction

The economic competitiveness of clean electricity generation in the United States will help determine the evolution of the power generation mix and the energy sector more broadly, and with it U.S. environmental quality and greenhouse gas emissions. When a project developer or electric utility is deciding whether and where to build a power generation asset, or a utility commission is deciding what projects to approve, it considers the relative economics of different project types and existing wholesale electricity market rates. Every project is affected by the interplay of technology characteristics and costs; local energy resources, construction costs, and operating costs; prevailing electricity prices; and financial variables. Those financial variables include economy-wide and electricity-specific inputs and policies, such as:

- Prevailing corporate tax rates and interest rates,
- Asset tax-depreciation schedules,
- Variations in capital and construction costs, and
- Federal and state tax credits and other incentives.

This interplay of factors has been broadly recognized and studied, with authors looking at modeled deployment impacts of policy changes (Mai et al., 2016), project data for specific technologies (Feldman et al., 2016), projections of future project costs (Bolinger et al., 2015), and regular compilation of project data (for example Wiser and Bolinger, 2016; Bolinger and Seel, 2016). Other authors have looked at the impact of electricity policies in the context of characterizing energy incentives more broadly (for example Harrison, 2015; CBO, 2015).

This article builds on this literature to explore the impact of changes

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Table 1
Summary of key inputs for the eight projects explored in this paper, including base costs (adjusted for each state), typical capacity factors, and current federal tax treatment.

Technology	Capacity (MW)	Capacity Factor	Base Capital Cost ($/W)	ITC (%)	PTC ($/MW)	Tax Depreciation Life (years)	Operating Life (years)
Large PV	150	0.22–0.31	1.7	30	0	5	25
Small PV	7	0.22–0.31	1.9	30	0	5	25
Onshore Wind	100	0.31–0.48	1.6	0	23	5	20
Offshore Wind	400	0.34–0.46	6.3	0	23	5	20
Geothermal	50	0.71–0.95	2.7	10	0	5	30
Biomass	50	0.83	3.8	0	11	5	30
Natural Gas, Combined Cycle	430	0.87	1.1	0	0	20	30
Natural Gas, Comb. Turbine	240	0.30	0.7	0	0	15	30

to these financial inputs on the relative economic favorability of different power generation asset types in different locations and under different policy scenarios. We present an integrated, multi-technology, state-level project finance cash flow model to allow policymakers and scholars to anticipate how proposed changes to energy and financial policies might affect the types of power generation assets that get built. The goal of this work is to better understand how current U.S. federal policies affect the economics of new electricity generation and to provide a tool, which we call the Project Finance Mapping Tool (PFMT), that can be used to rapidly compare potential outcomes under a wide range of technology cost, policy, and financial assumptions. In this paper, we focus on three policy tools, the federal tax provisions that provide the bulk of federal support to clean electricity: the investment tax credit (ITC), the production tax credit (PTC), and the accelerated depreciation of capital for tax purposes through the IRS Modified Accelerated Cost Recovery System (MACRS). The ostensible purpose of such subsidies is what we call *viability conversion:* transforming economically non-viable projects into economically viable projects. All other things being equal, without viability conversion the subsidy costs money without generating any new and additional deployment. However, the complexity of the current system can obscure when and how this happens. Geographic heterogeneity of generating resources, capital costs, and electricity system prices, as well as the interactions between tax credits, depreciation schedules, and state or regional policies make it difficult to assess where and how well the federal incentives are working.

We use the PFMT to look at all of the technologies that typically use project finance and how various policies affect their economic viability in all 50 states and the District of Columbia. We find that onshore wind power is the only renewable generation technology that experiences viability conversion in multiple states under current policies. We also find that even though costs have declined steadily for many renewable technologies, these technologies became less economically favorable from 2014 to 2015 because prevailing wholesale or system electricity prices declined even faster than the technology costs. However, as we will discuss in the policy implications section, even if federal incentives are not sufficient to allow new generation to undercut prevailing prices, those incentives can still be critical in reducing compliance costs with non-financial policies such as state-level renewable portfolio standards and other deployment mandates—state governments may institute more aggressive renewable goals if part of their cost is paid by federal taxpayers.

This paper proceeds as follows: The next section (§2) describes the methodology, definitions, and assumptions in our financial modeling of new electricity generation. That is followed in §3 by model results, which compares modeled prices to the prevailing system prices in all 50 states for eight typical new generation projects both unsubsidized and under current policies. Two key generation technologies—large-scale PV and onshore wind—are modeled under a variety of policy scenarios. The final section (§4) discusses the conclusions and policy implications of this work.

2. Methodology, definitions and assumptions

As noted, we developed a financial model, called the Project Finance Mapping Tool, to compare electricity generation project costs across three sets of characteristics: technology, geography, and policy. The software integrates information about energy resources, construction costs, state and federal incentives, and financial structures such as pass-through tax structures, to simulate year-by-year cash-flows for a variety of projects and policies. Hadley and Chinthavali (2016) provides the full model documentation and validation, so we will only briefly summarize the model here.

The model assumes an independent project structure, takes project characteristics as inputs, and solves for a needed price for the project's energy sales to achieve a specified desired lifetime return on equity (ROE) for the project investors or weighted-average cost-of-capital (WACC) for project developers. It then uses that price to generate a year-by-year project cash flow. Inputs include:

- Technology variables such as capital cost per watt, project size, construction timeline, project lifetime, operating and maintenance costs, and fuel costs.
- Geographic variables such as the quality of renewable resources (expressed as capacity factors), state incentives, and prevailing wholesale or system energy prices.
- Financial variables such as cost of debt and equity, ratio of debt to equity, applicable federal incentives, tax rates, ability to monetize tax benefits, and contract structure.

We explore the relative costs of eight typical projects using six different generation technologies: solar photovoltaics (PV), wind, geothermal, biomass, natural gas combined cycle, and natural gas combustion turbine.[1] We include two PV projects (7 MW and 150 MW), as state-level incentives often treat small and large PV projects differently, and both an onshore and an offshore wind project. Key variables for each technology are summarized in Table 1. In addition to these national values—largely taken from the Energy Information Administration's *Annual Energy Outlook 2016* (EIA, 2016a)—we adjust capital cost (EIA, 2010) and capacity factor (NREL, 2016) state by state to reflect local resources, construction, and land costs. We also include state-level incentives for energy generators based on the DSIRE database (NCCETC, 2016).

For this article, projects are assumed to use an idealized capital structure. We hold fixed a 60% initial debt-to-equity ratio, 18-year debt tenure, and a 7% WACC (11% ROE) for each project, though the model is designed to accommodate a wide range of capital cost and structure input assumptions. We assume that the project can fully monetize any available tax benefits, meaning a $1 tax credit has the same value as $1 of after-tax revenue. This is not typically the case, especially for renewable energy projects that are eligible for multiple tax benefits,

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[1] We do not include nuclear power among out typical projects because nuclear power plants are too large to use project finance, and so are not effectively modeled by our approach.