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Abstract

This paper develops an econometric forecasting system of energy demand coupled with engineering-economic models of energy supply. The framework is used to quantify the impact of state-level renewable portfolio standards (RPSs) achieved predominately with solar generation on electricity rates, electricity consumption, and environmental quality. We perform the analysis using Arizona's RPS as a case study. We forecast energy demand in Arizona out to 2035, and find by this time the state will require an additional 35 million MWh of electricity generation. If Arizona implements its RPS when supplying this electricity demand, we find there will be a substantial increase in electricity rates (relative to a business-as-usual scenario of reliance on gas-fired generation). Extending the current regime of tax credits can greatly reduce this increase, at the taxpayers' expense. We find that by 2025 Arizona's RPS will implicitly abate carbon dioxide emissions at a cost between $101 and $135 per metric ton, and by 2035 abatement costs are between $64 and $112 per metric ton (depending on the future evolution of nature gas prices).

Keywords: Electricity demand; Renewable portfolio standard; Solar; Carbon dioxide

1. Introduction

The growing challenge of climate change has led to a large variety of policy responses which aim to curb greenhouse gas emissions. In the energy sector, a policy response which is growing in popularity is to promote renewable energy by introducing renewable portfolio standard (RPS) legislation. Currently around 30 U.S. states have introduced mandatory RPS targets, which require electricity retailers to supply a certain minimum share of their electricity from eligible renewable resources. The expectation is that RPS policies will help to reduce reliance on fossil-fuels, promote sustainable energy, and control greenhouse gas emissions.[1]

When introducing RPS measures, it is important that policy makers are aware of the impacts of electricity supply policy on electricity rates, electricity consumption, and environmental performance. In this paper, we aim to quantify these impacts for renewable energy portfolios achieved predominately with solar generation. Although wind power is generally a cheaper renewable resource than solar, some jurisdictions only have a limited supply of windy land, and many U.S. states have adopted RPS policies with solar set-asides.

We perform our analysis using Arizona's electricity market as a case study. Arizona has adopted a RPS that requires electric utilities to generate 15% of their electricity from renewable energy resources by 2025,[2] which we extend to 25% by 2035. To meet this target a substantial contribution will come from solar power, and Arizona is often considered to be the solar capital of the United States. There is significant regional variation in the performance of renewable energy resources, and with most of Arizona's land exposed to more than 300 days of sunshine a year, an assessment of solar power in Arizona can reasonably be considered as an indication of the best likely performance of solar technology.

To analyze Arizona's energy future, this study develops an econometric forecasting model that identifies and measures the sensitivity of energy consumption to economic growth and energy

[1] Engel and Orbach (2008) consider why state governments introduce climate change initiatives, since global problems are not an obvious state issue. Similarly, Lyon and Yin (2010) present an empirical analysis of the political and economic factors that drive state governments to adopt RPS policies.

[2] Unlike some other states that set an aggressive standard but then give credit for existing projects, Arizona's RPS is focused on adding new renewable generation and so is considered by some commentators to be a high standard (e.g. Renewable Energy World, 2006).

prices. The model estimates end-use energy demand in each sector of the Arizona economy, including the residential, commercial, and industrial sector. A key advantage to the model is that it allows for interfuel substitution within these sectors.[3] The elasticities of substitution between the various fossil fuels and electricity are of critical importance in evaluating sustainability possibilities and in estimating the economic cost of environmental policies (Stern, 2012). Industrial users and large commercial users, in particular, are expected to substitute between fossil fuels with different carbon intensities (e.g. coal and natural gas), and non-fossil fuels (e.g. electricity from renewable energy sources), as relative fuel prices change.[4]

The energy demand model is then coupled with engineering-economic models of energy supply in which capacity, utilization rates, and heat rates determine the average cost of electricity generation. In turn, the cost of power generation determines electricity rates. Accordingly, this modeling framework estimates the annual impacts on electricity rates from different electric capacity plans, allowing for the endogenous response of electricity consumers to the associated rate impacts. The integrated framework is used to forecast out to 2035 the future consumption of electric power in Arizona and the cost of meeting that demand under different choices for new electricity generation capacity. In addition, the analysis takes into account the considerable uncertainty surrounding the future trajectories of natural gas prices by considering alternative gas price scenarios.

The evidence in the empirical literature on the impact of RPS measures on energy expenditures is mixed. Chen et al. (2009) review 31 studies on the cost impact of state or utility-level RPS legislation in the U.S. and find that while most predict higher electricity rates, 6 studies predict lower rates.[5,6] The studies reviewed by Chen et al. (2009) are typically based on simple

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[3] See Stern (2012) for a recent review of the interfuel substitution literature.

[4] There may also be some incentive for interfuel substitution in the residential sector.

[5] Fischer (2010) provides a theoretical analysis of why the predicted impacts of RPS can vary and finds the two driving factors are the elasticity of electricity supply from renewable energy sources relative to nonrenewable ones and the effective stringency of the target.

[6] Other recent papers which look at the cost of RPSs include Johnson and Moyer (2012) who consider the case of wind development in Illinois. They argue that complete RPS implementation will require significant decreases in renewables costs; otherwise it is not feasible under cost caps. Kung (2012) also looks at Illinois and points out that the capital cost dominates the price of wind electricity. Hence policies for wind electricity should aim at lowering the capital cost. In addition, Crane et al. (2011) consider a national RPS of 25% by 2025 and find it would likely be an economically efficient method only under favorable technology development assumptions.

spreadsheet models, and Chen et al. (2009) argue there is considerable room for improvement in the analytical methods, and accuracy, of the estimates. Our integrated energy model seeks to address this criticism. Moreover, the estimated construction costs of the widely deployed photovoltaic (PV) technology have fallen dramatically over recent years, while new solar thermal technologies with energy storage are also emerging. These developments call for new studies on the economic performance of solar.

Given the objective of this paper is to examine the cost of renewable electricity supply policy, we do not focus on demand-side policy initiatives. These include policies to induce electric utilities to reduce electricity consumption by their customers. In the U.S., states routinely set specific targets for reductions in energy consumption.[7] The comparison and evaluation of alternative demand-side measures deserves separate study. However, our modeling approach does estimate and control for on-going gains in energy efficiency over the forecast horizon.

The analysis proceeds as follows. Section 2 develops the econometric modeling framework in detail. In Section 3 we use the forecasting model to perform policy simulations and in section 4 we conclude.

2. The Econometric Forecasting Model

Total end-use electricity consumption has been growing rapidly in Arizona over recent decades, rising from 14 million MWh in 1970 to 73 million MWh in 2010. Arizona is becoming increasingly reliant on natural gas generation to meet this demand. Figure 1 illustrates that nearly all new electric power generation in Arizona since the late 1990s has been natural gas-fired generation. This reflects a national trend: since 1995, 80% of new capacity in the U.S. has been gas-fired units. A driving factor is the fact that natural gas plants are less capital intensive and do not involve the extensive and elaborate pollution control systems that many coal-fired plants require. In contrast, the capacity base for coal, nuclear and hydroelectricity has remained fairly constant over the last decade. These trends are reflected in the development of our baseline for

[7] For example, twenty four states (including Arizona) currently have long-term energy savings targets, or Energy Efficient Resource Standards (EERS). Arizona's EERS target includes the requirement that certain investor-owned utilities and rural electric cooperatives achieve cumulative savings equal to 22% by the year 2020.

forecasting analysis, where all new electricity demand is met by gas-fired generation and other generation sources remain at current levels.

Arizona's electric power industry generated a total of 112 million MWh of electricity in 2010, which is 35 million MWh greater than Arizona end-use. The surplus power is exported to other states, in particular Southern California. Much of this power is sold under long-term off-take agreements so exports are unlikely to respond quickly to policies that impact power generation and use in Arizona. The focus of this paper is therefore on the impacts of Arizona's electricity supply policy on its domestic electricity market.

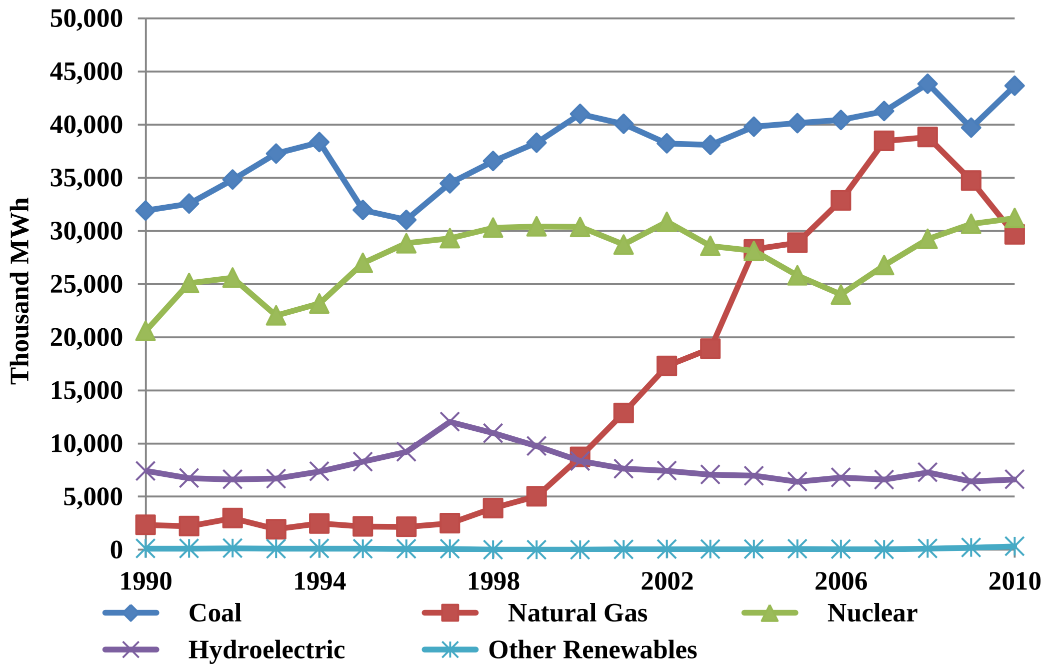

Figure 1: Total Electric Industry Power Generation by Primary Energy Source in Arizona

This paper uses an econometric forecasting model that determines electricity supply, demand, and prices, given exogenous assumptions for primary fuel prices, economic growth, inflation, and capacity expansion plans. This framework is built upon two modeling perspectives. First, the end-use demand for fuels in the residential, commercial, and industrial sectors are modeled from an economic perspective in which energy demand is a function of relative prices, exogenous demand shifters (such as the level of economic activity), and time trends to capture the effects of technological innovations and energy efficiency standards. Total electric power generation requirements are determined by adding predicted end-use electricity demand in Arizona, net electricity exports, and power line losses. Second, on the supply-side for electricity, an engineering-economic perspective is adopted in which generation capacity, utilization rates, and heat rates of operating units are specified exogenously, with the exception of electricity generation from natural gas, which is determined as the difference between demand and generation from all other sources. Hence, natural gas is modeled as the swing fuel, or the last units operated to meet system power load requirements, which is consistent with the recent past in Arizona. Therefore, the opportunity cost of electricity from alternative energy systems, such as solar thermal (i.e. Concentrated Solar Power), PV, and wind, is electricity produced from natural gas.

Carbon emissions are tracked for each sector of the economy, providing nearly complete accounting of carbon dioxide emissions in Arizona. Carbon emissions, therefore, are endogenous and depend upon energy prices and economic activity driving energy demand and the choice of electricity generation capacity.

There are five main components of the model. The first three include systems of energy demand equations for the residential, commercial, and industrial sectors. The fourth involves the demand for transportation fuels, including gasoline and diesel fuel. The fifth and final component involves the electricity generation sector. The following two sub-sections describe the formulation of the models within each of these components in more detail.

2.1 End-Use Energy Demand

The energy demand equations in the residential, commercial, and industrial sectors are specified as expenditure systems. This approach incorporates two key features of demand systems consistent with consumer utility maximization or producer cost minimization. The first feature is that relative prices in part determine the mix of fuels. The importance of relative price changes follows from the homogeneity condition of demand equations, which implies that if all prices increase by the same proportionate amount then total energy expenditures also increase by the same percentage. The other important property involves symmetry. If the demand for fuel oil increases when relative propane prices increase, then propane and oil are substitutes. In this case, the demand for propane should increase with relatively higher oil prices. An energy demand forecasting system with interfuel substitution should have these symmetric price effects.

Economists have developed a variety of methodologies for ensuring consistency between demand equations. One group of methods uses flexible functional forms to approximate systems of demand equations derived from neoclassical cost or expenditure functions. In particular, the translog (TL) model (Christensen et al. 1973), the generalized Leontief (GL) cost function (Diewert, 1971), and the dynamic cost-share linear logit (LL) model (Considine and Mount, 1984) continue to be widely used in the literature on energy and electricity demand modeling. For the purposes of this paper, we follow the dynamic cost-share LL model approach. Considine and Mount (1984) argue that this functional form is much better suited for modeling dynamic adjustments. A dynamic specification is essential because it is unlikely that energy consumers will respond fully to shocks within one period. The LL model can be specified so that it explicitly captures dynamic effects by including lagged quantities (rather than lagged cost shares, as is the case with the dynamic TL specification). This quantity based adjustment process ensures short-run elasticities are smaller than the long-run elasticities. In addition, Considine (1989) argues that the LL model is less likely to produce counter-intuitive results, such as positive estimates of own price elasticities, and so is better suited to satisfy the restrictions of economic theory. A further advantage to the LL approach is that it does not place any restrictions on autoregressive processes of structural error terms (Chavas and Segerson, 1986).

There are several applications of LL demand models that examine various aspects of energy demand. Jones (1995) applies the LL model to U.S. industrial energy demand and finds that it out performs other models in terms of fitting observed data and in providing sensible demand elasticities. Urga and Walters (2003) also look at U.S. industrial energy demand and find that the superior performance of the dynamic logit relative to the dynamic translog cannot be explained solely by dynamic model mis-specification or the inclusion of price-unresponsive non-energy fuel use data. Both studies conclude that a LL specification yields more robust results and so should be preferred in the empirical analysis of interfuel substitution.[8] Other empirical

[8] An alternative approach to interfuel substitution proposed recently by Serletis and Shahmoradi (2008) is to estimate semi-parametric functions that possess global flexibility: the Fourier and the Asymptotic Ideal Model. Although this facilitates estimation under weaker conditions than with parametric forms, Steinbuks (2012) points out that the implementation of these models is fairly complex and it is unclear how the signs and magnitude of the estimated elasticities correspond to those from the translog or linear logit models.

applications of the LL model include Considine (2000), Considine and Rose (2001), Brännlund and Lundgren (2004) and Steinbuks (2012).

This study adopts a standard, nested two–stage approach for the residential, commercial, and industrial sectors. The first stage determines the level of total energy consumption. The second stage model disaggregates aggregate energy consumption by fuel type. Appendix A describes the econometric formulation of this two–tiered model structure in detail. Appendix A also describes the energy demand model for the transportation fuels.

2.2 Electricity Production

The model computes electricity generation by fuel type on the basis of available capacity and average operating rates. Generation from capacity *i* in year *t* in megawatt hours is defined as:

$$G_{it} = H_i \times C_{it} \ , \tag{1}$$

where H_i is the number of hours capacity is operated and C_{it} is rated capacity in megawatts. Fuel demand is simply generation multiplied by the average heat rate:

$$F_{it} = HR_i \times G_{it} \ , \tag{2}$$

where HR_i is the heat rate in tons of oil equivalent per megawatt hour. The forecasts produced in section 3 assume fixed operating hours and heat rates over the forecast horizon, computed using historical values.

Generation from natural gas-fired capacity is determined by the difference between power demand and the sum of generation from other generation sources. Generation costs of each capacity type reflect variable costs of operation (including fuel costs) plus average fixed costs, and are used to compute an overall output-weighted average cost of generation. End-use electricity prices are then calculated by adding transmission and distribution charges to the average generation cost. The transmission and distribution costs are estimated using historic data by subtracting generation costs from end-use electricity prices. The model allows end-use electricity prices to vary with oil, coal, and natural gas prices, which then feedback on electricity demand and production. This formulation provides an integrated evaluation of electricity demand and fuel choice in power generation.

2.3 Model Overview

A list of the endogenous variables in the energy demand forecasting model appears in Table 1. Coal, petroleum, nuclear, hydroelectric, solar, other renewable sources, or natural gas-fired fossil fuel power generation can meet demand requirements. The cost share systems include an aggregate energy quantity equation. The quantities are derived by multiplying aggregate energy expenditures, which equal the divisia price index multiplied by the corresponding quantity index, by the respective cost share and then dividing by the appropriate price. The parameters of the energy demand models are estimated using the Generalized Method of Moments (GMM) estimator using annual data for the period 1972–2010 from the U.S. Energy Information Administration (EIA) State Energy Data System (2013).

Table 1: Model endogenous variables and identities

Endogenous Variables	**Type**[a]	**Endogenous Variables**	**Type**[a]
Residential Sector		*Commercial Sector*	
Divisia energy price	I	Divisia energy price	I
Aggregate energy quantity	B	Aggregate energy quantity	B
Cost shares & quantities		Cost shares & quantities	
Natural Gas	B	Natural Gas	B
Liquid Propane Gas, etc.	B	Petroleum Products	B
Electricity	B	Electricity	B
Electricity Generation		*Industrial*	
Generation & Fuel Use		Divisia energy price	I
Natural Gas	I	Aggregate energy quantity	B
Nuclear	I	Cost shares & quantities	
Coal	I	Natural Gas	B
Hydroelectric	I	Petroleum products	B
Other Renewables	I	Electricity	B
Electric power generation	I	Coal	B
Electricity consumption	I	*Transportation*	
Average Generation Costs	I	Gasoline in road travel	B
Retail Electricity prices	I	Diesel in road travel	B

[a] I = Identity or mathematical equality, B= Behavioral (i.e. econometric) equation.

2.4 Estimation Results

The econometric results from the estimation of the energy demand models for the residential, commercial, industrial, and transportation sectors of the Arizona economy are provided in full in Appendix B. All own price elasticities are negative and, therefore, consistent with economic theory. The own price elasticity of demand for electricity is very price inelastic, particularly in the short run, which is consistent with the findings of many other studies (recent examples include Serletis et al. (2010) for the U.S. and Steinbuks (2012) for the UK). This indicates that consumer expenditures rise sharply as electricity prices increase. For each sector, estimated energy demand fits the observed data well and the diagnostic tests support the model specifications (the test of the over-identifying restrictions cannot be rejected and the concavity conditions are correctly signed). Overall, the econometric results yield plausible estimates for the elasticities and suggest the forecasting model will perform well in policy simulations.

3. Simulation Analysis

We use the estimated energy demand model to project future energy consumption by sector in the Arizona economy from 2011 to 2035. We then consider the alternative electricity supply options available to Arizona to meet the forecast demand for electricity. The full simulation model, including the behavioral equations, the cost, generation, and retail rate equations for the electric power sector, and the carbon accounting relations, involves the simultaneous solution of 126 equations. Simulations are performed using TSP 5.1 Gauss-Newton algorithm.

The baseline projection assumes that all electricity demand beyond the existing (i.e. year 2010) generation base is supplied by new natural gas-fired generation from 2011 onwards. This option is intended to be a business-as-usual option in which Arizona continues as it has done in the recent past and serves as a point of comparison for evaluation of the full implementation of Arizona's RPS: 15% of electricity is generated from renewable energy resources by 2025 (plus intermediate targets are met). Beyond 2025, this scenario assumes Arizona continues to increase renewable generation at the same rate, reaching 25% by 2035. We consider an expansion of Arizona's current development path to achieve this target, which implies 86% of the renewable energy will come from PV and solar thermal systems, and the remainder from wind. The standard also requires 30% of the RPS target to be derived from distributed generation technologies from 2012 onwards, which in our forecasts comes from distributed PV systems. More details on Arizona's RPS are provided in Appendix C.

To evaluate these electricity supply policies, we require assumptions on economic growth, inflation, and primary fuel prices. The natural gas price in particular is a key variable in this study because it determines the marginal value of electricity generation costs, given that the model assumes by construction that natural gas is the swing fuel. However, there is considerable uncertainty surrounding future trajectories for natural gas prices. This uncertainty largely emanates from the supply-side, due to the uncertain future recovery of U.S. gas resources. In addition, on the demand-side, the electricity capacity choices made by U.S. states may influence gas prices. In this analysis, we treat the natural gas price as exogenous to Arizona's decision on whether or not to implement its RPS commitment, since the impact on demand for natural gas would likely be too small relative to national demand to significantly affect gas prices paid by consumers. However, if a large number of states pursue a common strategy, the impact on demand would be more than incremental and could drive gas prices.[9]

Therefore, to account for these factors, this study considers three scenarios with different natural gas price projections:

1. Reference scenario: projections for primary fuel prices and inflation are taken from the EIA's Annual Energy Outlook (AEO) 2013 Reference Case. This scenario assumes continued near-term gas production growth followed by a decline in U.S. production after 2020 (reflecting a current laws and regulations case). In addition, states generally meet their ultimate RPS targets.

2. High gas price scenario: reflects the possibility that the estimated ultimate recovery of shale gas resources is lower than in the reference scenario, and/or that states generally do not meet their RPS commitments and instead rely on gas-fired generation.

3. Low gas price scenario: reflects the possibility that the estimated ultimate recovery of shale gas resources is higher than in the reference scenario, and/or that states generally exceed their RPS commitments at the expense of gas-fired generation.

The projections for each scenario are summarized in Table 2. Each scenario is used in the evaluation of the baseline and the RPS policy. The projection for natural gas prices in the high gas price scenario is taken from the AEO 2013 low gas resource scenario, and in the low gas price scenario it is taken from the AEO 2013 high gas resource scenario.

For economic growth, this study assumes the long run average per capita growth rate displayed in Arizona over 1970-2011 will continue until 2035. This implies gross state product per capita grows at 1.6%. Finally, population growth rates are taken from projections by the Arizona Office

[9] Wiser and Bolinger (2007) review a number of studies which argue that the deployment of renewable resources may lead to reductions in the demand for and price of natural gas. They find these studies suggest that a 1% reduction in US natural gas demand could lead to long-term average wellhead price reductions of 0.8–2%.

of Employment and Population Statistics. These projections imply an average population growth rate of 1.6% over the forecast horizon, so population rises from 6.5 million in 2012 to 8.2 million in 2025 and to 9.6 million in 2035.

Table 2: Scenarios for primary fuel prices, inflation and economic growth

	Observed Level in 2010 (2010 $)	***Real average growth rate over 2010 – 2035 forecast horizon (%)***		
		Reference	High gas price	Low gas price
Oil price (per barrel)	$79.5	2.4	2.4	2.4
Natural gas price (per 1,000 cubic feet)	$4.1	2.1	3.2	0.1
Coal price (per ton)	$35.6	2.0	2.0	2.0
Inflation (2010 = 1.00)	1.00	1.8	1.8	1.8
Gross State Product per capita	$39,659	1.6	1.6	1.6

Projections are also required for the estimated costs of installing and operating new capacity, which are known as levelized costs. Levelized costs are defined as the variable costs of operation (including fuel costs), fixed operations and maintenance costs, investment in transmission upgrades, plus a capital cost recovery component which is the amortized capital costs of installation. We follow assumptions reported in the AEO 2013 to compute the levelized costs data. Hence, we assume a 30 year cost recovery period and use a 6.6% real weighted average cost of capital in the computation of the capital recovery factor. The capital recovery factor also takes into account pre-operation financing costs which depend on the length of the construction/licensing period and the profile of the costs during this period. The levelized costs are adjusted using the AEO 2013's location-based cost adjustment coefficients to take into account regional variation in the capital cost estimates. Operating and capital costs are estimated for a base year using AEO 2013 data and then projected into the future based upon the EIA's forecasts of future generation costs.

In the case of solar thermal technology, the EIA reports data for a representative solar thermal technology without integrated energy storage. However, the largest solar thermal projects in the pipeline in Arizona utilize parabolic trough technology with energy storage (such as the 340 MW Hualapai Valley Project, the 280 MW Solana Generating Station, and the 200 MW Kingman project). Therefore, we use the expected installation and operations and maintenance costs data for solar thermal technology with 6 hours of molten salt energy storage taken from Turchi et al. (2010).[10]

The levelized costs of solar and wind are highly sensitive to their operating rates, which can vary significantly by region. Therefore, this study uses operating rates for solar and wind projects from case study data in Arizona, rather than use the national averages reported by the EIA.[11] For solar thermal with energy storage, we use the 41% capacity utilization rate predicted for the Solana Generating Station currently under construction near Gila Bend.[12] For solar photovoltaic, we assume a 27% capacity utilization rate which is that expected for the Mesquite Solar project in Maricopa County.[13] If the solar operating rates could be increased even further, this would reduce the cost of solar generated electricity. For wind we assume a 22% capacity utilization rate which reflects the 2011 realized rate for the Dry Lake Wind Power Project in Navajo County (Arizona's first utility-scale wind farm).[14]

The levelized costs of each technology are plotted below in Figure 2. The levelized costs of PV, solar thermal and wind generation change in close proportion to the estimated change in capital costs, because in each case there are no fuel costs and relatively small operations and maintenance costs. Therefore, as the AEO 2013 projects capital costs for these technologies that tend to decline over the forecast horizon, Figure 2 shows the levelized costs are also expected to fall. Falling capital costs are mainly driven by learning by doing: equipment manufacturers, power plant owners, and construction firms gaining more experience with the technologies as more units enter service. Natural gas generation also experiences these effects, but the increasing natural gas prices offset the cost reductions. Thus the levelized cost of natural gas rises over time. Nonetheless, over the forecast horizon the costs of solar technologies remain an order of magnitude higher than natural gas.

[10] We obtain similar estimates for the levelized costs of solar thermal with energy storage if we use project data from the Solana Generating Station near Gila Bend.
[11] The capacity utilization rates used by this study for the dispatchable technologies are the rates reported by the AEO 2013.
[12] The expected annual production of this plant is 900 Gwh per year with a net capacity of 250 MW after station parasitic loads.
[13] Phase 1 of this project installed 150 MW generating capacity, which is expected to generate 350 Gwh per year.
[14] We use the realized rate rather than an expected rate for wind power following the discussion by Boccard (2009).

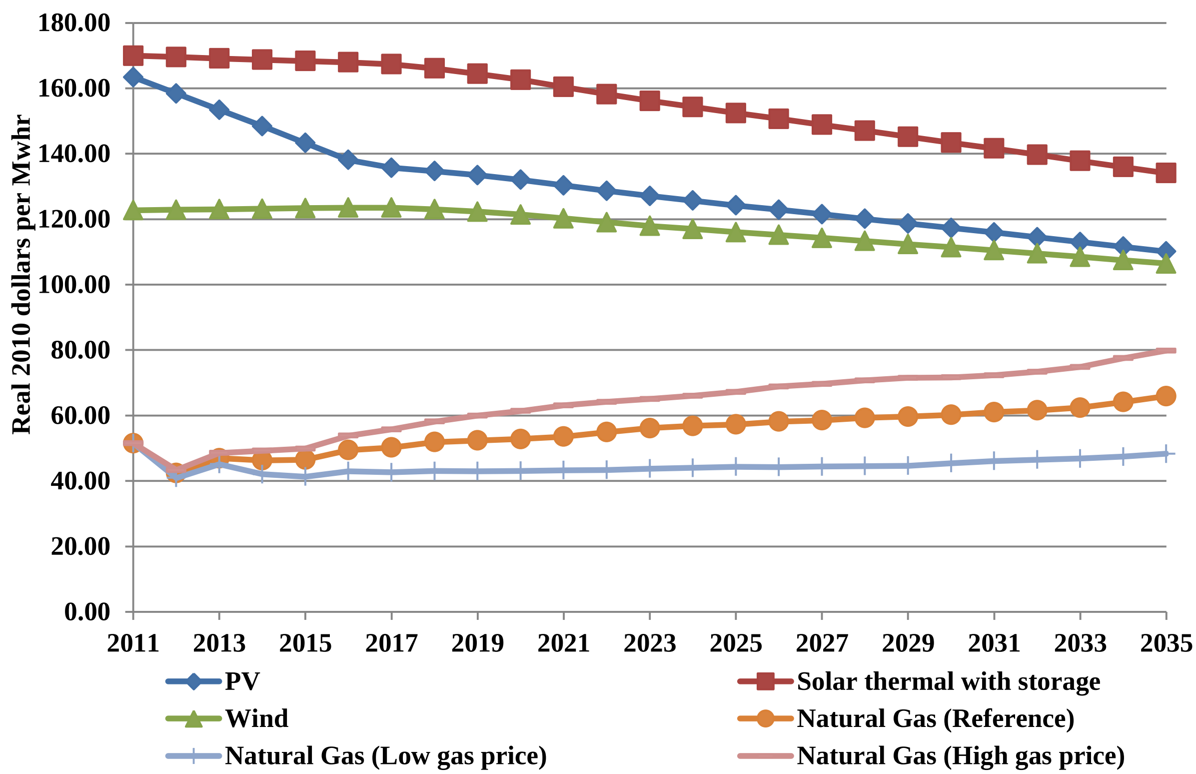

Figure 2: Levelized Costs of New Generation Capacity in Arizona

The levelized costs illustrated in Figure 2 do not take into account targeted tax credits such as the production or investment tax credit available for some technologies. These policies will significantly reduce the levelized cost estimates for these technologies, which in turn reduce generation costs and lower retail rates for electricity consumers. Therefore, we also consider the impact on electricity expenditures of the current regime of federal tax credits for renewable fuels, and calculate the cost of these policies to the taxpayer. That is, new solar thermal and PV plants are eligible to receive a 30 percent investment tax credit on capital expenditures and new wind plants are eligible to receive a $22 per MWh inflation-adjusted production tax credit over the plant's first ten years of service. We assume these tax credits for renewables are extended indefinitely.[15]

Levelized costs are widely recognized as a convenient summary measure of the overall competitiveness of different generating technologies. However, plant investment decisions in

[15] These policies have been extended (with or without modification) several times since their initial implementation.

practice are affected by the specific technological and regional characteristics of a project, which involve numerous considerations besides installation and operating costs (AEO 2013). For example, since load must be balanced on a continuous basis, dispatchable technologies whose output can be varied to follow demand generally have more value to a system than non-dispatchable technologies whose operation is less flexible and is tied to the availability of an intermittent resource. One way to take this into account would be to charge an intermittence penalty for renewables. On the other-hand, more reliable and consistent power output from renewable resources can be achieved using the solar thermal technology with energy storage considered in this analysis. In addition, in a system with rate of return regulation, the intermittence costs may be recovered by riding peaks in demand during hot summer afternoons, receiving high prices when solar sources produce power. For these reasons, we do not introduce an intermittence penalty in this analysis.

3.1 Baseline Forecast

Under the reference scenario, with an annual average increase in gross state product of 3.3%, total end-use energy consumption (including consumption of coal, natural gas, and petroleum products in the residential, commercial, industrial, and transportation sectors plus consumption of electricity including conversion and transmission losses) grows at 1.1% per annum from 2010 to 2035. Hence, the energy intensity of use (i.e. the ratio of total energy consumption to gross state product) declines on average 2.2% per year. This trend is driven by improving energy efficiency and is illustrated in Figure 3. Under the low gas price and high gas price scenarios, the average decline in energy intensity of use is very similar, at 2.15% and 2.25% per year respectively.

Natural gas use is projected to expand much faster than petroleum use, as illustrated for the reference scenario by Figure 4. Natural gas use grows at an average of 2.96%. Electricity use expands at 1.39% per annum and petroleum use expands at just 1.06% per annum. These projections imply that natural gas becomes a greater share of total energy consumption, at the expense of petroleum and electricity. In comparison, natural gas use grows at an average of 3.22% and 2.79% in the low and high gas price scenarios, respectively, reaching a total of 675 and 624 Trillion BTU by 2035.

In the reference scenario, total demand for Arizona electricity (i.e. electricity use plus estimated losses and net exports) is projected to rise steadily over the forecast horizon from 112 million MWh in 2010 to 130 million MWh in 2025 and to 147 million MWh in 2035. Therefore, 18 million MWh of new natural gas generation comes online by 2025 to meet this growing demand, rising to 35 million MWh by 2035. This is generated by 2,365 MW of new natural gas capacity in 2025, rising to 4,584 MW in 2035. One factor dragging down future demand for electric power is increasing real rates for electric power. Generation costs rise due to increasing real prices for natural gas assumed in the reference scenario and a rising share of natural gas in the electricity capacity portfolio. For instance, real average generation costs rise from \$48/MWh in 2010 to \$53/MWh in 2025 and to \$59/MWh in 2035 for a 0.8% annual average increase. Retail electricity prices move in tandem with these higher generation costs. In turn, the higher real electricity rates, along with technological progress and energy efficiency programs, induce energy conservation. For example, annual residential electricity consumption per customer, which has been on a long-run upward trend, is flat over the forecast horizon (12.9 MWh in 2010 and in 2035).

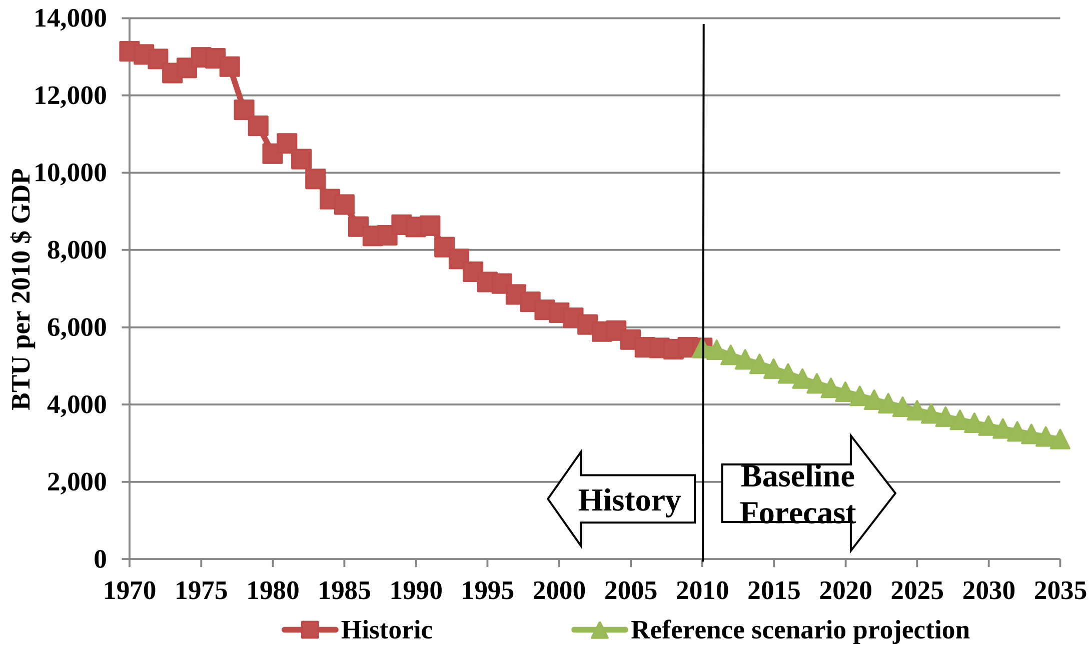

Figure 3: Historical and projected energy intensity of use

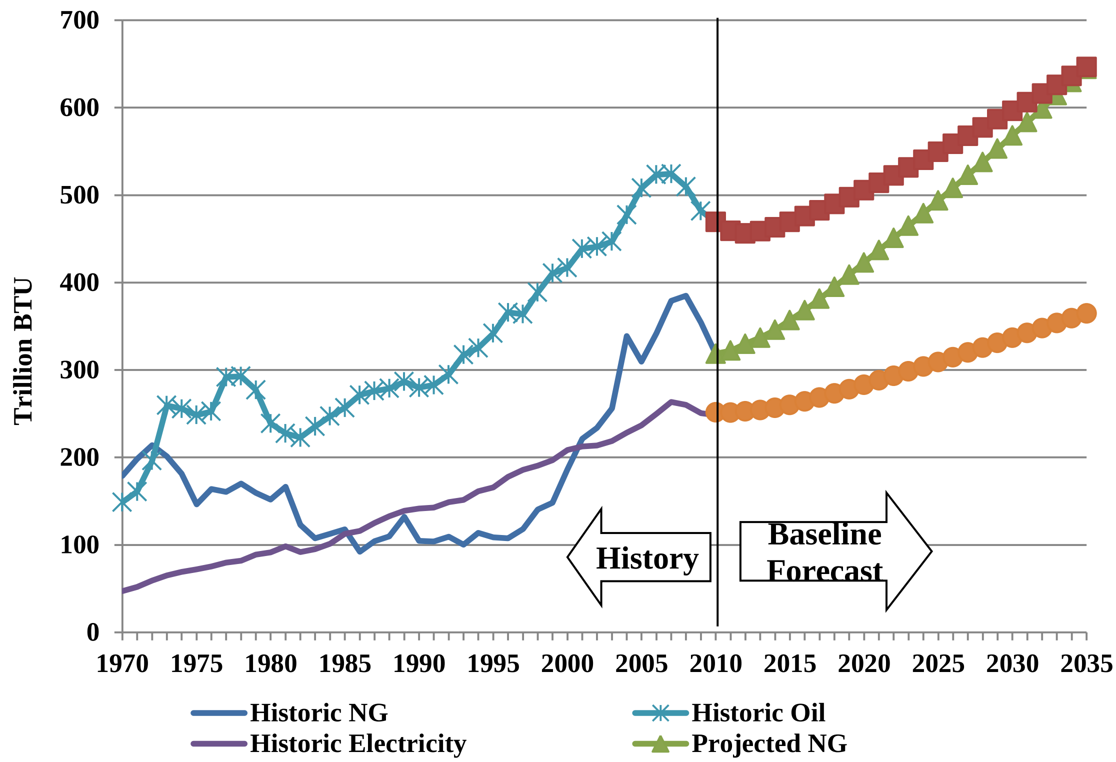

Figure 4: Historical and projected oil, natural gas, and electricity use

Finally, total carbon dioxide emissions steadily increase from 2010 levels of 97 million metric tons to 111 million metric tons by 2025 and to 127 million metric tons by 2035. These emissions result from the combustion of natural gas, coal, and petroleum products in the residential, commercial, industrial, and transportation sectors of the Arizona economy.

3.2 Renewable Portfolio Standard Forecast

To achieve Arizona's RPS, a significant amount of renewable electricity production capacity must be constructed. Table 3 shows the new nameplate capacity which must be added in each year to meet the RPS compliance schedule for each renewable technology according to our reference scenario forecasts. Under the RPS without tax incentives, a total of 10,011 MW of new PV, solar thermal, wind and distributed generation is added from 2011 to 2035 to meet the 25% RPS target. Under the RPS with tax incentives, the lower generation costs reduce electricity prices which in turn increase electricity demand. Hence the build out of renewables is greater still, with a total of 10,093 MW constructed by 2035. However, the new renewable generation is not sufficient to meet all new electricity demand in Arizona and so by 2035 there are 6.8 million MWh and 7.4 million MWh of new natural gas generation in the reference scenario without and with tax credits, respectively. The build out in the high and low gas price scenarios is not shown in Table 3 but the difference is negligible.

Table 3: New renewable energy resources added in MW due to the RPS [a]

	RPS – without tax credits				**RPS – with production and investment tax credits**			
Year	Solar Thermal	PV	Wind	Distributed PV	Solar Thermal	PV	Wind	Distributed PV
2011	22	39	15	83	22	39	15	83
2012	18	32	12	100	18	32	12	100
2013	31	56	21	52	31	56	21	52
2014	33	58	22	54	33	58	22	54
2015	34	61	23	56	34	61	23	57
2016	67	118	45	110	67	119	45	110
2017	69	123	47	114	70	124	47	115
2018	72	127	48	118	72	128	49	119
2019	74	132	50	122	74	132	50	123
2020	76	136	52	126	77	136	52	126
2021	79	140	53	130	79	141	53	130
2022	81	144	55	133	81	145	55	134
2023	83	148	56	137	84	149	57	138
2024	86	153	58	142	87	154	58	143
2025	88	157	60	146	89	158	60	147
2026	91	161	61	150	92	163	62	151
2027	94	166	63	154	94	168	64	156
2028	96	171	65	158	97	172	65	160
2029	99	175	67	163	100	177	67	164
2030	101	180	68	167	102	182	69	169
2031	104	185	70	171	105	187	71	173
2032	107	190	72	176	108	192	73	178
2033	109	194	74	180	111	197	75	182
2034	112	199	75	184	113	201	76	187
2035	115	204	77	189	116	206	78	191
Total	1,941	3,447	1,309	3,314	1,957	3,476	1,320	3,341

[a] Build out shown is for the reference scenario.

Table 4 summarizes the annual impacts of Arizona's RPS on electricity consumption, rates, and carbon dioxide emissions. A key result is that in each scenario, even the high natural gas price scenario and with tax credits for renewables, meeting the required renewable generation targets increases retail electricity rates over baseline levels.

We focus first on the reference scenario. Without tax credits, real average electricity rates across the residential, commercial, and industrial sectors increase by 8.1% above the baseline in 2025 and 10.1% in 2035. The percentage increase in average electricity rates rises over time, despite the fact that the costs of renewable generation fall, because more renewables enter the generation portfolio mix. Due to the higher rates, electricity use across these sectors falls 1.16% below the baseline in 2025, and 1.79% below the baseline in 2035. The implied own price elasticity of electricity demand is on average −0.13 over the forecast horizon, reflecting the inelastic nature of demand estimated by the econometric model (see Appendix B). Due to higher electricity prices, residential electricity consumption per customer now declines from 12.9 MWh in 2010 to 12.6 MWh in 2035. Introducing tax credits reduces the levelized cost of renewable generation, leading to a smaller increase in electricity rates for consumers. In this case, real average electricity rates increase 4.5% above the baseline in 2025, and 4.4% in 2035. In turn, the reduction in electricity use is fractionally smaller than without tax credits.

Given the very inelastic demand, when electricity prices increase in real terms, expenditures on electricity also increase. In the reference scenario, electricity consumers pay a total of $570 million more in real terms in 2025 under the RPS without tax credits than the baseline, and $385 million more under the RPS with tax credits (see Table 4). The additional electricity expenditures rise to $836 million and $491 million in 2035 without and with tax credits, respectively. What do these increases mean for households? The average monthly electricity bill for residential customers is predicted to increase in real terms from $118 in 2010 to $129 in 2035 under the baseline, to $137 in 2035 under the RPS without tax credits, and to $133 in 2035 under the RPS with tax credits.

Although tax credits can shield consumers from higher electricity rates, they come at a substantial cost to the taxpayer. Table 4 reports the total investment tax credit paid to new PV, solar thermal and distributed PV solar systems coming online in a particular year, plus the total production tax credit paid to wind generation in that year. In 2025 this total cost to the tax payer is $441 million, and in 2035 the cost is $534 million. Although these costs are much greater than the saved electricity expenditures in the corresponding year relative to the RPS without tax credits, it should be taken into account that the investment tax credit will lower the cost of electric power to consumers over the entire 30 year capital cost recovery period of the solar plant (since a smaller capital cost will need to be recovered each year). Therefore, the cost of tax credits to the government represents a saving which will (eventually) be made by electricity consumers.[16]

From an environmental perspective, the RPS involves significant reductions in greenhouse gas emissions. In the reference scenario without tax credits, annual carbon dioxide emissions are 5 million metric tons lower than baseline levels in 2025, and 11 million metric tons lower in 2035. With tax credits, the savings in carbon dioxide emissions under the RPS are fractionally smaller since there is a smaller reduction in electricity demand relative to the baseline.

The RPS policy involves new renewable generation effectively displacing new gas-fired generation. Thus if natural gas prices are lower than in the reference scenario, the RPS will become more expensive relative to the baseline, while high gas prices make the RPS relatively less expensive. Real average electricity rates increase by 14.5% and 7.2% above the baseline in 2035 in the low gas and high gas price scenarios respectively without tax credits, or by 8.2% and 1.8% respectively with tax credits. As a result, the average monthly electricity bill for residential customers is $10 and $6 above the baseline in 2035 in the low gas and high gas price scenarios respectively without tax credits, or $6 and $1 respectively with tax credits.

[16] Economically speaking, tax credits are transfer payments i.e. they redistribute income.

Table 4: Summary of annual impacts of Arizona's RPS on electricity use, electricity expenditures and CO2 emissions

	Baseline				**RPS – without tax credits**				**RPS – with production and investment tax credits**[e]				
Year	Electricity Demand[a]	Electricity Rates[b]	Electricity Expenditure[c]	CO2 emissions[d]	Electricity Demand[a]	Electricity Rates[b]	Electricity Expenditure[c]	CO2 emissions[d]	Electricity Demand[a]	Electricity Rates[b]	Electricity Expenditure[c]	Tax credits[f]	CO2 emissions[d]
Low gas price scenario													
2010	112	9.16	7,193	97	112	9.16	7,193	97	112	9.16	7,193	0	97
2015	115	8.90	7,280	98	115	9.12	7,426	97	115	9.04	7,373	186	97
2020	122	9.03	8,090	105	121	9.62	8,505	102	122	9.40	8,351	395	102
2025	130	9.11	8,971	112	129	10.03	9,642	107	129	9.68	9,385	441	107
2030	138	9.21	9,914	120	136	10.40	10,836	112	137	9.92	10,468	487	112
2035	146	9.38	10,978	128	144	10.74	12,095	117	145	10.15	11,615	531	118
Reference scenario													
2010	112	9.16	7,193	97	112	9.16	7,193	97	112	9.16	7,193	0	97
2015	115	9.06	7,391	98	115	9.27	7,529	97	115	9.19	7,489	185	97
2020	122	9.36	8,347	104	121	9.90	8,717	101	122	9.68	8,606	394	102
2025	130	9.62	9,392	111	129	10.40	9,962	106	129	10.05	9,777	441	106
2030	138	9.84	10,499	119	136	10.82	11,250	111	137	10.34	10,985	490	111
2035	147	10.19	11,796	127	144	11.22	12,632	116	145	10.64	12,287	534	116
High gas price scenario													
2010	112	9.16	7,193	97	112	9.16	7,193	97	112	9.16	7,193	0	97
2015	115	9.17	7,463	98	115	9.37	7,595	97	115	9.29	7,544	184	97
2020	122	9.66	8,567	104	121	10.15	8,899	101	121	9.93	8,750	392	101
2025	130	9.99	9,706	111	128	10.69	10,199	106	129	10.34	9,948	441	106
2030	138	10.32	10,929	118	136	11.14	11,552	111	137	10.67	11,190	491	111
2035	146	10.82	12,409	125	144	11.60	13,029	116	145	11.02	12,557	535	116

[a] Electricity demand is total electricity use plus estimated losses and net exports in million MWh. [b] Average electricity rates is an average end-use price across all sectors in 2010 cents per kWh. [c] Total electricity expenditures in 2010 $ million. [d] CO2 is in millions of metric tons. [e] RPS with production and investment tax credits assumes the 30 percent investment tax credit for solar and the $22 per MWh production tax credit for wind are extended indefinitely. [f] Cost of tax credits in a given year reports the total investment tax credit paid to new PV and solar thermal systems coming online due to RPS in that year, plus the total production tax credit paid to wind generation in that year (over and above the wind generation online in the baseline) in 2010 $ million.

Table 5 reports the implied cost per metric ton of avoided carbon dioxide emissions from achieving compliance with Arizona's RPS legislation. This is calculated as the increase in total real energy expenditures (i.e. expenditures on electricity, gas, coal and petroleum products in all sectors) above baseline expenditures in each year under the RPS without tax credits, divided by the estimated reduction in carbon dioxide emissions in the corresponding year. The results indicate that in 2011, the incremental increase in the RPS target in Arizona from 2.5% to 3.0% reduces carbon dioxide emissions at a cost of $174 per ton. This abatement cost declines as the capital costs of solar fall with technological progress, while natural gas prices rise which increases the levelized cost of natural gas generation. By the end of the forecast horizon, the implied costs of avoided carbon emissions are $112, $85 and $64 per ton in the low gas price, reference and high gas price scenarios, respectively. For comparison, the AEO 2013 reports that a carbon cost of around $15 per metric ton is typically used by utilities and regulators in their resource planning.[17]

Chen et al. (2009) report the implied carbon dioxide abatement costs of RPSs projected by the previous literature for the first year in which each state RPS reaches its ultimate target level. They find the implied costs range widely from −$427 to $181 per metric ton of carbon dioxide, with a median of $5 per metric ton. Our projections of an abatement cost between $101 and $135 per metric ton in the year 2025, when Arizona reaches its 15% RPS target, are above this median. This reflects that electricity rates are projected to increase to a greater extent than the median projected increase of 0.8%, or 0.05 cents / kWh found by the Chen et al. (2009) review. There are two main reasons why. First, despite the estimated cost of solar PV falling significantly in recent years, plus the higher capacity utilization rates from solar thermal technologies with energy storage, solar remains relatively costly compared to wind. The AEO 2013 reports the national average levelized cost of wind plants entering service in 2018 to be 84.8 (2010 $ / MWh), which is far below the levelized cost of solar power even in Arizona (see Figure 2). Thus other studies which consider RPS policies achieved with a greater share of wind generation will find lower rate impacts. Second, natural gas prices have been driven to historic

[17] We do not calculate the implied cost of avoided carbon dioxide emissions for the RPS with tax credits on an annual basis. This calculation could be misleading since, as noted above, the additional cost to the tax payer of investment tax credits in each year will be recovered over the lifetime of the plant. However, the total economic cost of the RPS will ultimately be similar with and without tax credits, because tax credits are transfer payments.

lows, partly due to surging supplies from shale energy production. Therefore, even with steep increases in real future gas prices, the cost of natural gas generation in this study remains lower than forecast by studies conducted in the past.

Table 5: Annual implied cost of avoided carbon dioxide emissions from implementing RPS (2010 $ per metric ton) [a]

Year	Low gas price scenario	Reference scenario	High gas price scenario
2011	174	174	174
2015	167	158	152
2020	148	133	120
2025	135	116	101
2030	125	103	86
2035	112	85	64

[a] Calculated as the increase in total real energy expenditures above baseline expenditures in each year without tax credits for renewables, divided by the estimated reduction in carbon dioxide emissions in the corresponding year.

4. Conclusions

Solar powered generation is in principle highly appealing. It represents an inexhaustible, clean resource which can help promote sustainability and energy independence, and reduce reliance on fossil fuels and exposure to the vagaries of primary fuel prices. Over recent years the cost of PV technology has fallen markedly, and the U.S. like some other countries is experiencing a boom in solar powered generation, driven by RPS policies and tax incentives. Therefore, solar energy is set to play an increasingly important role in a future where reducing greenhouse gas emissions is a priority.

This paper quantifies the state-level impact of a predominantly solar powered renewable mix on electricity consumption, prices and carbon dioxide emissions using Arizona as a case study. Over the period 2011-2035, we find that implementing Arizona's RPS would lead to sharp increases in electricity rates without tax credits. Electricity rates increase 8.1% and 10.1% over the baseline in 2025 and 2035, respectively, in the reference scenario without tax credits. Consequently, energy expenditures rise and the implied cost of avoided carbon emissions by the peak target year in 2025 is in the region of $101 and $135 per metric ton. Extending the current regime of tax credits indefinitely will greatly reduce the increase to just 4.5% and 4.4% above the baseline in 2025 and 2035, respectively, although at the expense of the tax payer.

These results highlight the need for progress beyond the rate of technological advancement forecast in this analysis for solar to become cost effective in the near future. One means to achieve lower levelized costs of solar generation is to increase operating rates. For instance, in this paper we assume solar thermal will operate with a capacity factor of 41% over the forecast horizon, while Turchi et al. (2010) explain that further progress in energy storage systems could yield capacity factors as high as 65% while maintaining an optimum levelized cost. The solar industry recognizes this challenge to increase operating rates and lower the actual delivery price of energy from these facilities.

Caution should be taken in interpreting the results as a case for delaying the push towards solar until capital costs have fallen further, for a number of reasons. Firstly, we focus on the energy costs of RPSs and the implied cost of carbon abatement, but there may be other benefits to solar development. For example, the construction and operation of solar energy may create green jobs and production. Secondly, we examine the impacts of state-level RPS policy (since in practice RPS programs are being implemented by U.S. states), and we do not expect there to be important effects from the implementation of Arizona's RPS at the national level. Nonetheless, if a large number of states collectively delay their deployment of solar energy, it is likely to impair technological progress in solar resources, because the forecast reduction in capital costs by the EIA's AEO is driven by learning factors. In addition, there may be natural gas price feedback effects if the alternative is consistently more gas-fired generation. Thirdly, over-reliance on natural gas may also leave the portfolio of generation assets under-diversified. Fourthly, there is great uncertainty regarding the true social cost of carbon dioxide emissions and so in this paper we do not attempt to judge whether carbon abatement, even at a high cost, is in the interests of society.

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Appendix A. Mathematical Specification of End-Use Energy Demand

The residential, commercial, and industrial sector end-use demand models involve a non-homothetic two-stage optimization framework. The first stage determines the level of total energy consumption. The second stage model disaggregates aggregate energy consumption by fuel type. The first tier assumes an aggregate energy demand relationship:

$$\ln Q_{st}^{d} = \theta_s + \kappa_s \ln\left(\frac{P_{st}^{d}}{PGDP_t}\right) + \mu_s \ln X_{st} + \sigma_s CDD_t + \tau_s T_t + \lambda_s \ln Q_{st-1} + \varepsilon_{st} \ , \qquad \text{(A.1)}$$

where Q_{st}^{d} is a divisia quantity index of total energy demand for sector *s* in period *t*, P_{st}^{d} is a divisia index of aggregate fuel prices, $PGDP_t$ is a price deflator, X_{st} is a demand shifter that equals real disposable income per capita for the residential sector or economic production for the commercial and industrial sectors, CDD_t is cooling degree days, T_t is a time trend for technological innovations and energy efficiency, $\theta_s, \kappa_s, \mu_s, \sigma_s, \tau_s, \lambda_s$ are unknown parameters to be estimated, and ε_{st} is a random error term. For the residential sector, we account for the effect of a change in population on total energy demand by scaling Q_{st}^{d} by the population of Arizona.

The divisia price index is a share weighted moving average of logarithmic first differences in fuel prices defined by the following identity:

$$P_{st}^{d} = P_{t-1}\left[1 + 0.5\sum_{j=1}^{n}\left(S_{jt} + S_{jt-1}\right)\left(\ln P_{jt} - \ln P_{jt-1}\right)\right] , \qquad \text{(A.2)}$$

where *j* indexes the fuels used in the particular sector. For instance, prices for electricity, liquid propane gas, and natural gas comprise the divisia price index for the residential sector. The corresponding divisia quantity index is defined as aggregate energy expenditures divided by the divisia price index.

This specification assumes that the fuels in the energy price index are weakly separable from other goods and services. In other words, the marginal rate of substitution between two fuels is independent of the rate at which aggregate energy substitutes with other goods. Substitution possibilities between energy and other goods and services are likely to be limited within the time span considered in this study.

In the second stage, a system of share equations determines the mix of fuels within each sector's energy aggregate. The unrestricted linear logit model of cost shares is as follows:

$$S_{it} = \frac{P_{it}Q_{it}}{C_t} = \frac{e^{f_{it}}}{\sum_{j=1}^{n} e^{f_{it}}} \, \forall i \ , \qquad \text{(A.3)}$$

where:

$$f_{it} = \alpha_i + \sum_{j=1}^{n}\beta_{ij}\ln(P_{jt}) + \gamma_i Q_t + \sigma_i CDD_t + \phi \ln(Q_{it-1}) + \varepsilon_{it} \ , \qquad \text{(A.4)}$$

and where Q_{it} is the quantity of fuel *i* in period *t*, P_{it} is the price of fuel *i*, C_t is expenditure on fuels in the aggregate, CDD_t is cooling degree days, $\alpha_i, \beta_{ij}, \gamma_i, \eta_i, \phi$ are unknown parameters to be estimated, and ε_{it} is a random disturbance term. The inclusion of Q_t in equation (A.4) allows for non-homothetic demand functions within a two-stage demand model similar to the formulation developed by Segerson and Mount (1985).

Substituting (A.4) into (A.3), taking logarithms, normalizing on the n^{th} cost share, and imposing symmetry and homogeneity following the procedures developed by Considine and Mount (1984), yields the following share system:

$$\ln\left(\frac{S_{it}}{S_{nt}}\right)=(\alpha_i-\alpha_n)-\left[\sum_{k=1}^{i-1}S_k^*\beta_{ik}^*+\sum_{k=i+1}^{n}S_k^*\beta_{ik}^*+S_i^*\beta_{in}^*\right]\ln\left(\frac{P_{it}}{P_{nt}}\right)$$
$$+\sum_{k=1}^{i-1}(\beta_{ik}^*-\beta_{kn}^*)S_k^*\ln\left(\frac{P_{kt}}{P_{nt}}\right)+\sum_{k=i+1}^{n}(\beta_{ik}^*-\beta_{kn}^*)S_k^*\ln\left(\frac{P_{kt}}{P_{nt}}\right)+(\gamma_i-\gamma_n)\ln Q_t \qquad \text{(A.5)}$$
$$+(\sigma_i-\sigma_n)\ln(CDD_t)+\phi\ln\left(\frac{Q_{it-1}}{Q_{nt-1}}\right)+\left(\varepsilon_{it}-\varepsilon_{nt}\right),$$

for all fuels, i, in the cost share model, where the S_k^*s are mean cost shares. The energy cost share systems for the residential, commercial, and industrial sectors all include equations of this basic form. Equations (A.1) and (A.5) contain lagged quantities, which allow dynamic adjustments in demand and the computation of short and long-run elasticities. The price and income (output) elasticities are share weighted functions of the parameters. The adjustment parameter, ϕ, determines the difference between short and long-run elasticities.

The end-use energy demand equations may capture reductions in energy demand through improvements in energy efficiency in two ways. First, by controlling for the relative price of energy. Second, by the inclusion of time trends designed to capture the effects of non-price induced technological innovations and energy efficiency standards on energy consumption over time. This modeling approach reflects the explanation given by Birol and Keppler (2000) that the two main options to influence energy efficiency are changes in relative prices and technological change that increases the productivity of each energy unit.

A baseline projection of the demand for gasoline and diesel fuel is required in order to track carbon emissions from the transportation sector. Unlike the residential, commercial and industrial sectors, very limited or no interfuel substitution yet occurs in the transportation sector. Therefore, the transportation models in this sector take the same form as equation (A.1). In this case, the demand shifter includes real personal disposable income and price is the real price including taxes.

This study does not use the linear logit cost share system to model the derived demand for fuels in electric power production. This is because this approach would not explicitly incorporate capacity constraints. Moreover, a demand system estimated during a period with coal, fuel oil, and gas-oil would most likely not be applicable to one with a substantial share of natural gas. Although relative prices for these fuels do indeed provide estimates of how heat and utilization rates vary with relative fuel prices, the relative environmental costs and benefits of these fuels must also be considered. Environmental concerns are likely to be a major factor in the conversion of oil-fired electric power generation capacity to natural gas. Operating hours for coal capacity are quite likely at their maximum on occasions during our sample period, given necessary outages for maintenance. If oil capacity is replaced by natural gas, and coal operation hours and capacity are fixed, then relative prices cannot affect gas generation because it is swing capacity. Introducing relative price effects in the electric power sector, therefore, is a moot issue given these assumptions.

Appendix B. Econometric Results for Arizona Energy Demand

This Appendix describes the econometric results following the estimation of the energy demand models for the residential, commercial, industrial, and transportation sectors of the Arizona economy. The presence of total energy quantity on the right-hand side of the cost share equations requires an instrumental variable estimation to avoid simultaneous equation bias in the estimated coefficients. The Generalized Method of Moments (GMM) estimator is employed, which corrects for heteroscedasticity and autoregressive moving average error components in the stochastic error terms. The strategy for selecting the instrumental variables is the same for each sector: using prices lagged one-period, quantities lagged two periods, a time trend, and lagged values of the exogenous variables in the total energy quantity models, such as the personal disposable income or production.

The GMM estimates for the residential energy model, which contains three estimating equations, appear below in Table B1. The parameters reported in the top half of Table B1 correspond with those that appear in the log cost share ratio equations given by (A.5) in Appendix A. These parameter estimates have no clear, direct interpretation. Nevertheless, seven of the ten parameters of the residential cost share system are statistically significant, as indicated by probability values approximately equal to zero. To achieve an understanding of their implications, the elasticities of demand are reported in Table B2, which we will turn to shortly.

Reported in the center of Table B1 are the parameter estimates from equation (A.1) in Appendix A. The double log partial adjustment formulation of the total energy demand equation implies that the coefficients on price and the other exogenous variables in the equation are short-run elasticities. For example, the short-run own price elasticity of total residential energy demand, which is the sum of electricity, natural gas, and petroleum products, is -0.085. Also included in this equation is real per capita personal disposable income as an exogenous demand shifter. We find that a 1% increase in per capita disposable income leads to a 0.3% increase in total energy demand in the short-run. In addition, we include the total cooling degree days in 1 year as a measure of energy demand associated with cooling in Arizona and find that a 1% increase leads to a 0.1% increase in total energy demand in the short-run.

The summary fit statistics reported in Table B1 result from computing the predicted cost shares and using the cost share identity to compute predicted quantities. A static method was used so that past predictions of lagged quantities are not used. Although a dynamic simulation, which involves using lagged endogenous quantities, is used in the forecasts, a static method of fit assessment is preferred so that errors are not propagated. This method reveals that the residential model provides an excellent fit of the quantities as reflected by the R-squared measures of fit in Table B1. Moreover, the Durbin-Watson statistics do not indicate there is an auto-correlated pattern in the residuals.

The own price, cross price, output, and weather elasticities for the residential sector appear in Table B2. In all cases, we find the own price elasticities to be negative as expected. Focusing on the gross elasticities, the own price elasticity of demand for electricity is -0.025, which is very price inelastic. This elasticity is insignificantly different from zero. The gross, own price elasticities for liquid propane gas and natural gas are slightly larger although still inelastic, and are significant at the 10% level.

Table B1: Parameter Estimates and Summary Fit Statistics for Residential Sector

Cost Share System			
Parameters[a]	Coefficient	t-statistic	P-value
β_{12}	1.534	1.0	[0.316]
β_{23}	-0.856	-3.2	[0.001]
β_{13}	-0.866	-12.3	[0.000]
ϕ	0.780	19.3	[0.000]
γ_1	0.075	0.2	[0.810]
η_1	0.679	6.1	[0.000]
α_1	-5.503	-6.0	[0.000]
γ_2	0.222	0.3	[0.794]
η_2	1.475	4.1	[0.000]
α_2	-11.895	-4.3	[0.000]
Dependent variable:[b] $\ln(Q_e/POP)$			
Constant	-1.819	-3.4	[0.001]
$\ln(P_e$ / PGDP)	-0.085	-3.1	[0.002]
ln(Real Personal Disposable Income per capita)	0.291	3.0	[0.002]
$\ln(Q_{e,t-1}/POP)$	0.567	6.5	[0.000]
Trend	-0.002	-1.2	[0.222]
ln(CDD)	0.095	2.1	[0.039]
	Correlation	Durbin	
Dependent Variable	Coefficient	Watson	
Natural Gas	0.998	1.965	
Liquid Propane Gas	0.995	2.057	

Electricity	0.999	2.451
Total Energy Consumption per capita	0.953	2.412

[a] 1 = natural gas, 2 = liquid propane gas, 3 = electricity. See equation (A.5).

[b] See equation (A.1).

The gross elasticities assume that the level of total household energy demand is held constant. In reality, changing relative fuel prices affect the price of aggregate fuels to households that in turn affects the level of energy consumption. The second group of elasticities in Table B2, labeled net elasticities, account for these effects on total energy consumption. The net, own price elasticities of demand are larger in absolute terms. This reflects the negative own price elasticity of demand for aggregate household energy demand. The real per capita disposable income elasticities are also larger than the gross income elasticities, which measure how substitution possibilities vary with the level of income. The net income elasticities for natural gas, liquid propane gas, and electricity are 0.31, 0.35, and 0.29, respectively.

The net long run elasticities are reported in the last panel of Table B2. These elasticities are a function of the net elasticities divided by one minus the respective adjustment parameters. As expected, the long-run own price and income elasticities are substantially larger than the gross and short-run net elasticities. The long-run own price elasticity of demand for electricity is -0.28 with income elasticity of 0.62. Finally, the net long run elasticities for cooling degree days show that a greater demand for cooling tends to raise demand for natural gas, liquid propane gas, and electricity.

The objective function value of the GMM estimator is distributed as a Chi-Squared statistic, providing a test of the over-identifying restrictions for the model. For the residential model the probability value for the over-identifying restrictions is 9.3, suggesting that the restrictions cannot be rejected at the 5% level. Hence, the overall model appears to be supported by the data sample.

The curvature conditions, which follow from consumer utility maximization, are checked at the mean of the data by computing the Eigen values of the first derivatives of the estimated demand functions. For consistency with economic theory, the implicit expenditure function should be concave, which occurs when the Eigen values are less than zero. The residential estimates imply that these conditions are satisfied. Hence the residential energy demand functions are properly signed and on this basis provide intuitively plausible results for policy simulations. In summary, the fit of the household sector model is excellent, the elasticities of demand are very reasonable, and the diagnostic statistics support the specification.

Table B2: Own Price, Cross Price, Output and Weather Elasticities for Residential Sector

Quantities	Natural Gas Price	Liquid Propane Gas price	Electricity Price	Disposable Income per capita	Cooling Degree Days
	Gross Elasticities				
Natural gas	-0.187	0.078	0.109	0.056	0.529
t-statistic	-2.7	1.7	1.9	0.2	5.8
P-value	[0.007]	[0.098]	[0.057]	[0.821]	[0.000]
Liquid Propane Gas	0.392	-0.509	0.118	0.204	1.325
t-statistic	1.7	-1.8	0.5	0.3	3.9
P-value	[0.098]	[0.075]	[0.584]	[0.798]	[0.000]
Electricity	0.021	0.004	-0.025	-0.018	-0.150
t-statistic	1.9	0.5	-1.5	-0.3	-6.6
P-value	[0.057]	[0.584]	[0.137]	[0.783]	[0.000]
Quantities	***Net Elasticities***				
Natural gas	-0.200	0.065	0.096	0.308	0.146
t-statistic	-3.0	1.3	1.7	2.5	2.1
P-value	[0.003]	[0.179]	[0.099]	[0.013]	[0.034]

Liquid Propane Gas	0.389	-0.512	0.115	0.351	0.222
t-statistic	1.6	-1.8	0.5	1.4	2.2
P-value	[0.100]	[0.073]	[0.593]	[0.154]	[0.029]
Electricity	-0.049	-0.065	-0.095	0.286	0.081
t-statistic	-1.9	-2.4	-4.1	2.9	2.0
P-value	[0.064]	[0.017]	[0.000]	[0.003]	[0.043]
Quantities	***Net Long-Run Elasticities***				
Natural gas	-0.882	0.324	0.467	0.847	0.752
t-statistic	-2.7	1.5	1.8	1.0	2.1
P-value	[0.006]	[0.132]	[0.079]	[0.336]	[0.037]
Liquid Propane Gas	1.776	-2.323	0.529	1.298	1.551
t-statistic	1.6	-1.9	0.6	0.5	2.2
P-value	[0.099]	[0.054]	[0.577]	[0.607]	[0.030]
Electricity	-0.066	-0.140	-0.275	0.617	0.070
t-statistic	-1.2	-2.6	-3.2	2.3	1.5
P-value	[0.246]	[0.010]	[0.001]	[0.021]	[0.138]

The findings from the econometric estimation of the commercial energy demand model are similar to the residential sector results. As Table B3 indicates, seven out of the ten parameters in the commercial cost share system are significant at the 5% level. In the aggregate commercial energy demand equation, the short-run aggregate price elasticity of demand for energy is -0.03. The overall fit of the commercial sector is also quite good, while the Durbin-Watson statistics do not suggest the presence of serial correlation in the error terms.

Commercial sector economic activity is used to shift the overall level of aggregate commercial energy use. The elasticities for the commercial sector are reported in Table B4. Again, all own price elasticities are negative as expected. The short-run own price elasticity for electricity in the commercial sector is equal to just -0.01 and is insignificantly different from zero. The long-run price elasticity of demand for electricity is -0.11 and is also insignificant. Like the residential sector, the test of the over-identifying restrictions for the commercial model cannot be rejected. Overall, we again find that the econometric results yield plausible estimates for the elasticities and the model will likely perform well in policy simulations.

Table B3: Parameter Estimates and Summary Fit Statistics for Commercial Sector

Cost Share System			
Parameters[a]	Coefficient	t-statistic	P-value
β_{12}	2.683	2.3	[0.020]
β_{23}	-1.242	-9.4	[0.000]
β_{13}	-0.879	-22.8	[0.000]
ϕ	0.817	9.1	[0.000]
γ_1	-0.019	-0.2	[0.822]
η_1	0.184	2.0	[0.044]
α_1	-1.460	-1.1	[0.288]
γ_2	-0.190	-1.0	[0.330]
η_2	1.866	3.5	[0.001]
α_2	-11.900	-2.2	[0.027]
Dependent variable:[b] $\ln(Q_e)$			
Constant	1.136	0.4	[0.653]
$\ln(P_e$ / PGDP)	-0.026	-0.7	[0.464]
ln(Commercial Production)	0.264	2.1	[0.034]
$\ln(Q_{e,t-1})$	0.702	6.0	[0.000]
Trend	-0.004	-0.5	[0.649]
ln(CDD)	0.033	0.4	[0.663]
	Correlation	Durbin	
Dependent Variable	Coefficient	Watson	

Natural Gas	0.995	2.295
Petroleum Products	0.995	1.957
Electricity	0.999	1.073
Total Energy Consumption	0.996	1.425

[a] 1 = natural gas, 2 = petroleum products, 3 = electricity. See equation (A.5).

[b] See equation (A.1).

Table B4: Own Price, Cross Price, Output and Weather Elasticities for Commercial Sector

Quantities	Natural Gas Price	Liquid Propane Gas price	Electricity Price	Commercial Production	Cooling Degree Days
	Gross Elasticities				
Natural gas	-0.220	0.117	0.103	-0.011	0.103
t-statistic	-3.7	3.2	3.2	-0.2	1.2
P-value	[0.000]	[0.001]	[0.002]	[0.880]	[0.221]
Liquid Propane Gas	0.444	-0.239	-0.205	-0.182	1.784
t-statistic	3.2	-2.2	-1.8	-1.0	3.4
P-value	[0.001]	[0.028]	[0.067]	[0.321]	[0.001]
Electricity	0.015	-0.008	-0.007	0.008	-0.082
t-statistic	3.2	-1.8	-1.5	0.6	-4.2
P-value	[0.002]	[0.067]	[0.146]	[0.573]	[0.000]
Quantities	***Net Elasticities***				
Natural gas	-0.223	0.114	0.100	0.261	0.036
t-statistic	-3.9	3.0	2.8	2.2	0.4
P-value	[0.000]	[0.003]	[0.005]	[0.030]	[0.662]

Liquid Propane Gas	0.443	-0.239	-0.206	0.216	0.092
t-statistic	3.2	-2.2	-1.8	2.0	0.4
P-value	[0.002]	[0.027]	[0.066]	[0.047]	[0.675]
Electricity	-0.007	-0.029	-0.029	0.266	0.030
t-statistic	-0.2	-1.0	-1.1	2.1	0.4
P-value	[0.831]	[0.320]	[0.292]	[0.035]	[0.661]
Quantities	***Net Long-Run Elasticities***				
Natural gas	-1.214	0.630	0.553	0.832	0.173
t-statistic	-2.5	2.5	2.1	1.5	0.4
P-value	[0.012]	[0.013]	[0.040]	[0.140]	[0.681]
Liquid Propane Gas	2.427	-1.308	-1.127	0.003	1.190
t-statistic	2.5	-1.8	-1.8	0.0	0.4
P-value	[0.011]	[0.066]	[0.075]	[0.996]	[0.694]
Electricity	0.008	-0.115	-0.110	0.924	0.061
t-statistic	0.1	-1.0	-1.0	1.6	0.4
P-value	[0.952]	[0.328]	[0.304]	[0.114]	[0.685]

The econometric results for the industrial sector are reported in Tables B5 and B6. Several different specifications were tested. However, unsatisfactory results with positive own price elasticities called for an examination of the consumption of the four fuels. This reveals large, coincidental swings in natural gas and coal consumption during the 1970s and 1980s. Hence we hypothesize that natural gas and coal are weakly separable from electricity and petroleum products. As a result, a two tiered model is estimated: the first tier models the competition between natural gas and coal (Table B7) and the second tier models the demand for the natural gas and coal aggregate and how it substitutes with petroleum products and electricity (Table B6). The coal and natural gas substitution model yields correct signs on the estimates of the own and cross price elasticities of demand for these fuels, where the own price elasticities of demand in the long-run are -2.6 for coal and -0.7 for natural gas.

For the industrial sector model, the tests of the over-identifying restrictions are not rejected. The estimates also satisfy the curvature conditions, implying that the demand equations are consistent with producer cost minimization. Referring to Table B6, we find that like the residential and commercial sectors, the short-run demand for electricity is very price inelastic with a net own price elasticity of -0.025. This elasticity increases in the long-run to -0.232.

The final block of estimated econometric equations includes the demands for gasoline and diesel fuel used in transportation. These equations are estimated to track carbon emissions from the transportation sector. The results of this estimation appear in Table B8. The short and long-run price and income elasticities of demand are the correct sign. Like electricity, the short-run demand for these fuels is very inelastic indicating that consumer expenditures rise sharply as prices increase.

Table B5: Parameter Estimates and Summary Fit Statistics for Industrial Sector

Cost Share System Parameters [a]	Coefficient	t-statistic	P-value
β_{12}	-0.645	-2.1	[0.032]
β_{23}	-1.036	-12.4	[0.000]
β_{13}	-0.946	-14.8	[0.000]
ϕ	0.940	22.4	[0.000]
γ_1	0.136	0.7	[0.453]
α_1	-1.996	-0.8	[0.432]
γ_2	-0.187	-0.7	[0.483]
α_2	2.585	0.7	[0.495]
Dependent variable: [b] $\ln(Q_e)$			

Constant	1.392	1.0	[0.312]
$\ln(P_e / PGDP)$	-0.035	-0.8	[0.397]
ln(Industrial Production)	0.036	0.5	[0.631]
$\ln(Q_{e,t-1})$	0.878	8.9	[0.000]
Trend	-0.001	-0.4	[0.671]

Dependent Variable	Correlation Coefficient	Durbin Watson
Natural Gas & Coal	0.842	3.225
Petroleum Products	0.668	2.176
Electricity	0.958	2.495
Total Energy Consumption	0.728	2.546

[a] 1 = natural gas and coal, 2 = petroleum products, 3 = electricity. See equation (A.5).

[b] See equation (A.1).

Table B6: Own Price, Cross Price, and Output Elasticities for Industrial Sector

Quantities	Natural Gas & Coal Price	Petroleum Product Prices	Electricity Price	Industrial Production
	Gross Elasticities			
Natural Gas & Coal	-0.101	0.066	0.034	0.146
t-statistic	-1.6	1.2	0.8	1.0
P-value	[.110]	[.239]	[.396]	[.310]
Petroleum Products	0.064	-0.041	-0.023	-0.176
t-statistic	1.2	-0.5	-0.4	-0.8
P-value	[.239]	[.623]	[.664]	[.402]
Electricity	0.010	-0.007	-0.003	0.010
t-statistic	0.8	-0.4	-0.2	0.2

P-value	[.396]	[.664]	[.820]	[.875]
Quantities	***Net Elasticities***			
Natural Gas & Coal	-0.107	0.060	0.028	0.041
t-statistic	-1.7	1.1	0.7	0.5
P-value	[.089]	[.292]	[.504]	[.631]
Petroleum Products	0.058	-0.048	-0.030	0.029
t-statistic	1.0	-0.6	-0.5	0.4
P-value	[.296]	[.562]	[.597]	[.656]
Electricity	-0.012	-0.029	-0.025	0.036
t-statistic	-0.4	-0.8	-1.1	0.5
P-value	[.676]	[.403]	[.280]	[.625]
Quantities	***Net Long-Run Elasticities***			
Natural Gas & Coal	-1.742	1.063	0.523	1.002
t-statistic	-1.6	1.0	0.9	0.4
P-value	[.119]	[.313]	[.391]	[.682]
Petroleum Products	1.026	-0.748	-0.439	-0.570
t-statistic	1.0	-0.5	-0.5	-0.4
P-value	[.315]	[.594]	[.647]	[.660]
Electricity	-0.016	-0.296	-0.232	0.341
t-statistic	0.0	-0.6	-0.8	0.6
P-value	[.961]	[.535]	[.439]	[.542]

Table B7: Estimated Parameters and Price Elasticities for Industrial Fuel Sub-Aggregate

	Coefficient	t-statistic	P-value
Parameters			
α_1	-0.569	-1.1	[0.274]
β_{12}	-0.031	-0.1	[0.953]
ϕ	0.683	6.6	[0.000]

Quantities	Natural Gas Price	Coal Price
	Short-Run Elasticities	
Natural Gas	-0.220	0.220
t-statistic	-1.9	1.9
P-value	[0.053]	[0.053]
Coal	0.812	-0.812
t-statistic	1.9	-1.9
P-value	[0.053]	[0.053]
	Long-Run Elasticities	
Natural Gas	-0.693	0.693
t-statistic	-2.8	2.8
P-value	[0.005]	[0.005]
Coal	2.561	-2.561
t-statistic	2.8	-2.8
P-value	[0.005]	[0.005]

Table B8: Parameter Estimates & Elasticities of Demand for Gasoline and Diesel Fuel

	Coefficient	t-statistic	P-value
Dependent variable: $\ln(Q_{gasoline})$			
Constant	1.132	4.4	[0.000]
$\ln(P_{gasoline} / PGDP)$	-0.070	-3.3	[0.001]
ln(Real Personal Income)	0.193	3.2	[0.001]
$\ln(Q_{gasoline,t-1})$	0.638	5.9	[0.000]
Dependent variable: $\ln(Q_{diesel})$			
Constant	-2.205	-2.9	[0.003]
$\ln(P_{diesel} / PGDP)$	-0.063	-1.0	[0.295]
ln(Real Personal Income)	0.398	3.9	[0.000]
$\ln(Q_{diesel,t-1})$	0.553	4.8	[0.000]

Dependent Variable	Correlation Coefficient	Durbin Watson
Gasoline	0.992	1.174
Diesel	0.971	1.643

Quantities	Gasoline Price	Diesel Price	Income
	Short-Run Elasticities		
Gasoline	-0.070		0.193
t-statistic	-3.3		3.2
P-value	[0.001]		[0.001]
Diesel		-0.063	0.398
t-statistic		-1.0	3.9
P-value		[0.295]	[0.000]
	Long-Run Elasticities		
Gasoline	-0.194		0.533

t-statistic	-2.1		23.6
P-value	[0.040]		[.000]
Diesel		-0.142	0.889
t-statistic		-0.9	11.3
P-value		[0.343]	[0.000]

Appendix C. Renewable Portfolio Standard scenario development

In November 2006, Arizona passed a RPS that legally mandates electric utilities to generate 15% of their electricity from renewable energy resources by 2025. The standard also requires that 30% of the total renewable energy portfolio is derived from distributed generation technologies from 2012 onwards. Half of the distributed generation must be from residential installations and half from non-residential, non-utility installations. Investor-owned utilities and electric power cooperatives serving retail customers in Arizona, with the exception of distribution companies with more than half of their customers outside Arizona, are subject to the standard. The RPS also specifies intermediate targets and the full compliance schedule from 2010 onwards is given by Table C1 below. Beyond the 15% target in 2025, we assume Arizona continues to increase the target at the same rate (i.e. an additional 1% annually), reaching 25% in 2035.

As a state well known for its sunshine, a large contribution to Arizona's RPS target is expected to be made by solar technologies. However, with the recent approval of the 500 MW Mohave County Wind Farm project, it is clear that wind power is also a viable electricity source in Arizona, despite the limited availability of windy land. In this study, the RPS policy takes into consideration renewable projects currently operating and under development in Arizona to construct the path towards the 15% renewable generation target by 2025. Hence, 46.2% of new renewable generation is provided by PV, 39.5% solar thermal, and 14.3% wind. This relative development path of PV, solar thermal and wind generation closely matches that forecast for the Southwest region of the Western Electricity Coordinating Council by the AEO 2013 (taking the implied generation from the forecast build out of new renewable capacity, given the capacity utilization assumptions made by this study). In addition, it is assumed that the distributed generation is met by PV systems in the residential and commercial sector.

Table C1: Full RPS compliance schedule for Arizona

Year	Overall % RPS Target	% of Target from Distributed Generation	Year	Overall % RPS Target	% of Target from Distributed Generation
2010	2.5	20	2023	13.0	30
2011	3.0	25	2024	14.0	30
2012	3.5	30	2025	15.0	30
2013	4.0	30	2026	16.0	30
2014	4.5	30	2027	17.0	30
2015	5.0	30	2028	18.0	30
2016	6.0	30	2029	19.0	30
2017	7.0	30	2030	20.0	30
2018	8.0	30	2031	21.0	30
2019	9.0	30	2032	22.0	30
2020	10.0	30	2033	23.0	30
2021	11.0	30	2034	24.0	30
2022	12.0	30	2035	25.0	30

Figure C1 below gives the levelized costs for distributed generation technologies. The levelized costs are calculated using the most recently available data published by the National Renewable Energy Laboratory (2013) on the installation and operations and maintenance costs of residential and commercial PV systems. The capacity utilization rate is to be the same as for utility PV installations (i.e. 27%). It is assumed that residential systems are less than 10 KW, and commercial systems are between 10-100 KW. Advantages of distributed generation include that it reduces the amount of electricity lost during transportation over power lines and that it reduces the need for investments in transmission and distribution infrastructure. Hence in our model we assume there are no electricity losses from transportation or necessary transmission investments from distributed generation technology. When evaluating the RPS with tax credits, we assume the 30% investment tax credit is also available for distributed generation.

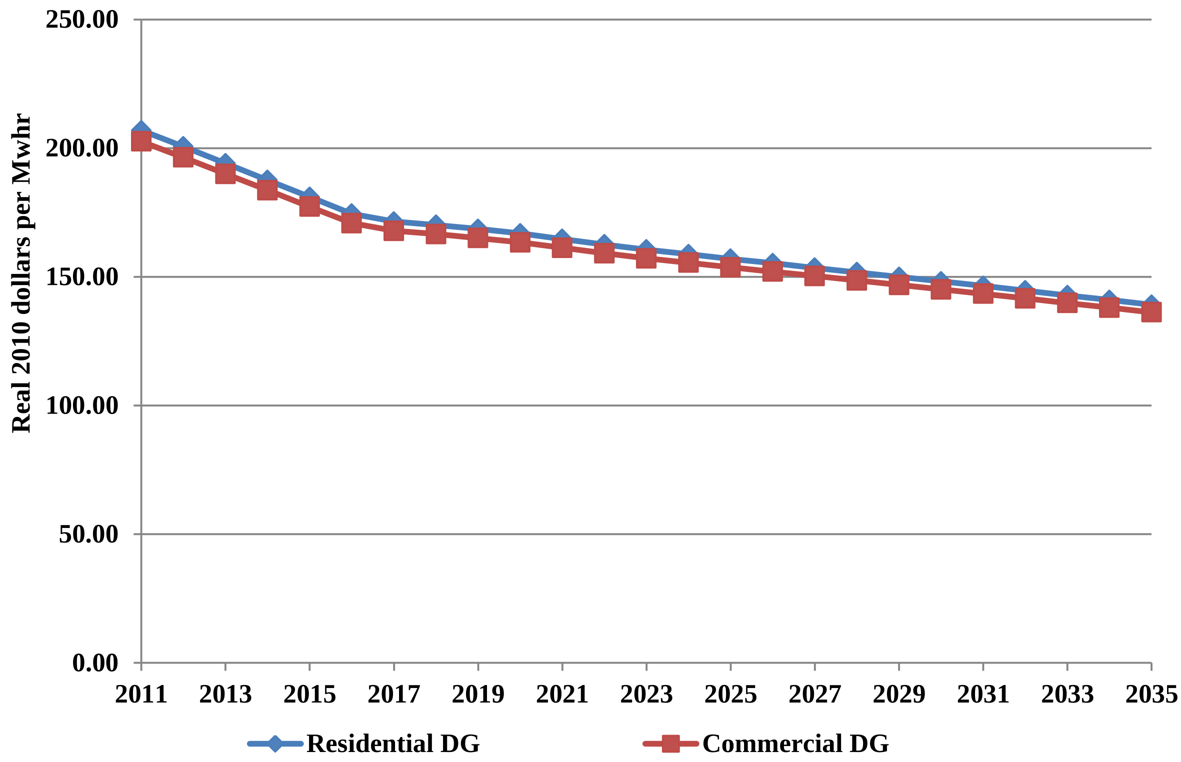

Figure C1: Levelized Costs of New Distributed Generation PV Capacity