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Feasibility of U.S. renewable portfolio standards under cost caps and case study for Illinois

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HIGHLIGHTS

- ▶ RPSs mandate that generation by non-hydro renewables in the U.S. double by 2025.
- ▶ Implementation of many RPSs is impossible without decreases in renewable costs.
- ▶ The Illinois wind requirement can largely be met by existing Iowa windpower.
- ▶ Placing technology carveouts under one cost cap allows pernicious interactions.
- ▶ The Illinois RPS statute combines different objectives inherently in conflict.

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ABSTRACT

Recently enacted state renewable portfolio standards (RPSs) collectively require that U.S. electricity generation by non-hydro renewables more than double by 2025. These goals are not certain to be met, however, because many RPSs apply cost caps that alter requirements if costs exceed targets. We analyze here the 2008 Illinois RPS, which is fairly typical, and find that at current electricity prices, complete implementation will require significant decreases in renewables costs even given the continuation of federal renewables subsidies. Full implementation is possible but not assured. The statutory design raises additional concerns about unintended potential consequences. The fact that windpower and solar carveouts fall under a single cost cap means that in failure mode, a less cost-effective technology can curtail deployment of a more cost-effective one. Adjacent-state provisions mean the bulk of the RPS can be met by existing wind facilities, and that new wind builds will likely occur in Iowa. The Illinois RPS, like that of many other states, appears to combine objectives inherently in conflict: preferences for local jobs, for specific technologies, for environmental benefits, and for low costs. Revisiting the legislation may be needed to make legislative success likely and to ensure that failure modes do not compromise goals.

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1. Introduction to renewable portfolio standards in the U.S.

Renewable portfolio standards (RPSs) – requirements that qualifying renewables produce at least some designated portion of the electricity sold in a given region (Rader and Norgaard, 1996; Berry and Jaccard, 2001) – mandate a significant transformation of the U.S. electricity system in coming decades. RPSs recently enacted by 29 states will, if met, collectively require that U.S. electricity generation from qualified renewables more than

double by 2025, to ~9% of the nation's electricity, up from ~4% (non-hydro) in 2009 (EIA, 2011b; DSIRE, 2011; UCS, 2011). Interest in a national level RPS is high as well. House Bill HR 2454, which passed the House in 2009 but did not make it to a vote in the Senate, would have imposed a national requirement of ~20% renewables generation by 2020 (Wiser et al., 2007), twice as large as combined state RPS requirements. Given the magnitude of these proposed changes, it is worth examining the feasibility of existing legislation. We examine the recently enacted Illinois RPS, a fairly typical statute that can be a useful model for understanding implications of renewables mandates more widely in the United States.

Analyzing a single state can produce national-level insight because many existing state RPS statutes are broadly similar

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(Rabe, 2007). The definition of qualified renewables generally includes wind, solar photovoltaic, solar thermal generation, and biofuels. (Inclusion of hydropower and solid waste combustion varies, but these are not expected to be a significant portion of new capacity. EAI, 2011a.) While some states restrict a portion of their requirements to particular generation types (e.g. separate requirements for solar in IL), in all statutes the majority of the requirements can be met by windpower, the lowest-cost non-hydro renewable generation technology at present (EAI, 2011a). Most RPSs also share a common means of defining renewable requirements (as a percentage of annual retail sales) and a common enforcement mechanism (purchase of Renewable Energy Credits, or RECs, which are awarded to qualifying generators for each MWh of power produced). Utilities may purchase RECs either bundled with or independent of actual electricity sales; they then tender the credits to the administering agency. RECs therefore serve two necessary functions - subsidizing renewable electricity and demonstrating RPS compliance - without further complicating electricity markets.

Most RPSs are also similar in phase-in speed, beginning with a relatively modest initial requirement of a few percent of annual retail sales and then ramping up at about a percentage point or two per year over a decade to a final target of 10–25% (Fig. 1). Because most state RPSs were implemented in a relatively tight span of 5 years (from 2006 to 2011), their phase-in will produce a steady increase in U.S. demand for renewables generation.

The recent origin of most state RPSs means that states have little experience base to guide their expectations, as there are few useful long-term examples of how renewables costs evolve as an RPS matures. Studies of the short-term initial phases of young RPSs have focused primarily on the volume of renewables installed rather than on prices (Menz and Vachon, 2006; Wisner et al., 2007; Carley, 2009; Yin and Powers, 2010; Delmas and Montes-Sancho, 2011) (with some exceptions, e.g. Wisner et al.,

2007; Chen et al., 2007). The few early RPSs that are old enough to be near full implementation are not good analogues for the 2006–2011 statutes, since all involve special conditions or circumstances that differentiate them from more recent statutes. Iowa, the earliest RPS (1983), had requirements so small ($\sim 1\%$ of state electricity sales; DSIRE, 2011; EIA, 2009b) that they could not be expected to affect the renewables industry significantly. Maine (2000) allowed existing facilities to contribute to the renewable portfolio and the RPS was initially met by existing hydropower rather than new construction (Wisner et al., 2007). Texas (1999) possesses such anomalously strong wind resources that development of windpower in the state is now driven largely by federal subsidies, with state REC prices as low as \$1 per MWh (Wisner and Bolinger, 2011). Current construction implies that Texas wind capacity will reach its 10 GW target almost 15 yrs ahead of RPS-mandated requirements (AWEA, 2010). The lack of precedent for the 2006–2011 RPSs means that predicting the evolution of renewables implementation under these statutes requires new analysis.

In the analysis that follows, we first review the implementation of cost-limiting mechanisms (“cost caps”) in U.S. renewable portfolio standards, and demonstrate by back-of-the-envelope calculation that many state RPSs appear viable only if renewables costs fall (Section 2). We then turn to Illinois in particular and evaluate in more detail the feasibility of the Illinois statute. We describe the Illinois statute (Section 3), consider the likely siting of new wind capacity and site-dependent effects on costs (Section 4), and then compute trajectories for the Illinois cost cap and for the cost of fulfilling the state RPS at current renewables costs (though under a variety of electricity price forecasts) (Section 5). Because the purpose of this work is to evaluate feasibility, our methodology in Section 5 is an “endmember analysis”. That is, for factors that are uncertain, we consistently choose assumptions that lie in a plausible range but at the end of that range that is optimistic for renewables and for RPS fulfillment. If the RPS mandate is not fulfillable under these optimistic assumptions, we can then robustly conclude that at current renewables costs, it is not fulfillable in any foreseeable scenario. After making this demonstration, we then compute the *minimum* necessary declines in renewables costs that could allow fulfillment of the Illinois statute (Section 6) and discuss their likelihood (Section 7). We conclude with a discussion of the broader implications of the Illinois example (Section 8). Four appendices describe acronyms used throughout this work, assumptions behind the “end-member analysis”, details of feasibility calculations, and the treatment of different electricity customers in the Illinois legislation (Appendices A, B, C, and D, respectively).

2. Cost caps in U.S. renewable portfolio standards

RPS legislation may be driven by any or all of several separate motivations, including environmental protection (both for air quality and climate purposes); support of the nascent renewables industry; and creation of local jobs (UCS, 2010). The details of state RPSs suggest that multiple motivations are often present. Stimulating local jobs appears to be a common goal, since locally generated power is often given favorable treatment. Supporting the renewables industry is likely also a common goal, as many statutes appear to assume that by requiring a large enough volume of renewables generation, they can help the industry reduce costs (through economies of scale and/or industry learning). These statutes contain cost caps that limit the total expenditure of subsidies at a value too small to allow full implementation in the current cost landscape. In other words, RPS success hinges on the

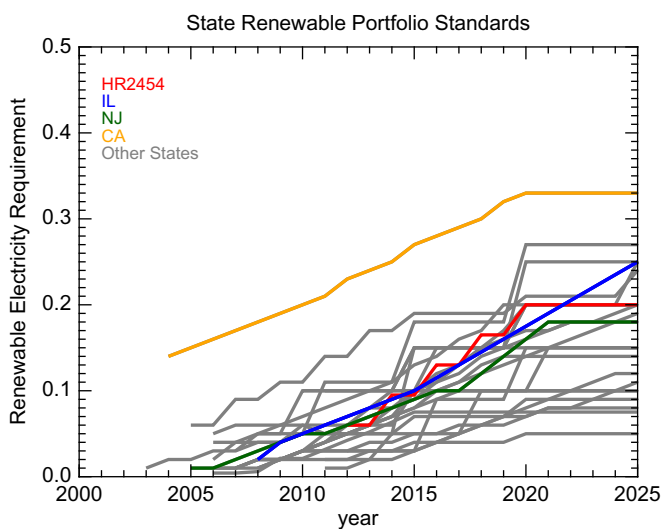


Fig. 1. Total renewables generation requirements as percentages of retail sales for 27 states and the District of Columbia (all who list requirements in the DSIRE (2011) database), and for the proposed federal standard of HR2454. Several statutes discussed in the text are highlighted. While the details of implementation can vary from state to state, with the exception of California the overall targets and phase-in rates are broadly similar. RPS requirements tend to begin at a low value of a few percent of total generation, increase at a rate of a percentage point or two per year, and top out at $\sim 20\%$. The clustering of RPS legislation in 2006–2011 means that the bulk of U.S. renewables requirements reach their peak in 2020–2025. For Maine, we show only the portion of the RPS that must be satisfied by new builds.

assumption that the “renewables premium” – the excess cost of renewables over their expected revenues from electricity sales – will drop enough to allow the legislation to reach its stated goals.

Cost caps in RPS statutes fall into two broad types, one of which typically implies an expectation of eventual decreases in renewables premiums. Under any RPS, private investors will add renewables capacity as long as it is profitable to do so, i.e. as long as the available subsidy they can receive per unit of power generated (generally cost-capped REC sales + federal subsidies) meets or exceeds the renewables premiums they must bear. Because a cost cap limits the magnitude of that subsidy, it allows legislators to privilege one type of risk over another. The cap becomes relevant only if renewables generation cost exceeds legislative expectations, and in that event it limits consumer or taxpayer spending at the a trade-off of failure to achieve the RPS goals. RPSs cost caps can be categorized according to their means of implementation: they either (1) impose non-compliance penalties on utilities if the RPS requirement is not met, or (2) freeze the RPS requirement if costs to consumers exceed some benchmark value, generally a benchmark percentage of wholesale or retail electricity sales.

RPS cost caps of type 1 (e.g. CT, DE, NH, NJ, MA, MD, ME, PA, RI, and TX, UCS, 2008), with penalties specified in dollars per non-compliant unit of energy (\$/MWh), should result in either full compliance with the statute or near-complete lack of compliance. If renewables premiums are lower than mandated penalties, investors will build renewables capacity and be confident that the REC price will compensate them for the extra cost of renewables generation. If renewables premiums are higher, investors will decline to build and utilities will opt to pay penalties instead of purchasing RECs.¹ RPS cost caps of type 2, on the other hand, appear to be driven by industry support motivations, and in failure mode would result in partial compliance. In these statutes, the cost cap is set as a fixed dollar amount or a fraction of electricity sales. The capped total subsidy then remains approximately constant (rising only with electricity sales or legislated increases in the cap) while the renewables requirement ramps up over time, so that the available subsidy per unit of renewable energy declines. The cost cap is always set to be large enough to stimulate investment initially, when renewables requirements are low, but typically small enough that the renewables premium must eventually decrease in order to achieve full compliance. If renewables premiums do not decline sufficiently, a point will arrive where the capped subsidies over the lifetime of a generation plant no longer exceed the renewables premium and renewables investment will cease.² The final outcome would then be a smaller-than-anticipated pool of renewables generators who receive higher-than-anticipated REC prices (in \$/MWh). States adopting this approach (e.g. CA, CO, IL, MI, MO, MT, NC, NM, NY, OH, OR, and WA, UCS, 2008) generally set their final caps lower than the current renewables premium, suggesting that the legislators assume that enactment of the RPS will result in a gradual lowering of renewables costs.

It is apparent even with back-of-the-envelope estimates that many type 2 cost caps, including that of Illinois, represent a “bet” on a lowered renewables premium. The Illinois cap limits the total cost of REC sales to 2% of retail sales on a 25% RPS requirement, meaning the price support available to each unit of renewable energy is no more than 2%/0.25 = 8% of the retail price. Since wholesale rates

are approximately three times less than retail rates, the cap allows a wholesale renewables premium of $3 \times 8\% \sim 25\%$. But the cost of generation by the cheapest qualifying renewable in Illinois, wind-power, is approximately double the wholesale price, i.e. its premium is $\sim 100\%$. Even with the inclusion of price support from the federal Production Tax Credit and Investment Tax Credit (henceforth “PTC”), which reimburse qualifying renewable generators for up to 30% of the construction costs, capped REC sales in Illinois cannot make up the remaining necessary subsidy. (See Appendix C for further discussion of the PTC.)

The Illinois cost cap is in fact even tighter than the above estimates imply, because the RPS contains a small ($\sim 1.5\%$) but expensive solar requirement that would consume significant amounts of the available subsidy. The cost of solar generation is somewhat uncertain at present, especially after recent declines, but in 2011 was approximately six times the national mean wholesale rate or two times the retail rate. The total cost of the solar requirement can then be estimated as $\sim 1.5\% \times 2 = 3\%$ of retail sales, or, with the PTC providing $\sim 30\%$ support, 2% of retail sales, equivalent to the entirety of the Illinois capped subsidy.

The discrepancy between the current cost landscape for renewables and that envisioned by the Illinois RPS statute is not atypical, and many state RPSs would require drops in renewables premiums of similar magnitude for full implementation. Of several type 2 RPSs examined (CO, IL, OH, WA, and NJ), only those of WA and NJ are feasible under current conditions. (See Table 1, which shows current renewables premiums for wind and solar and cost-capped state price supports, and Appendices C.1.1 and C.1.2 for detailed discussion of the premiums calculation.) These comparisons suggest that any concerns about the feasibility of the Illinois RPS statute would be widely shared across states.

The reductions in renewables premiums needed for RPS success can be achieved through either or both of two mechanisms:

Table 1

Comparison for selected states of renewables premiums, i.e. the price support required for renewables generation, vs. legally provided price supports for renewables: the federal PTC and cost-capped state REC sales. All are shown in comparable units, given as cost per unit energy (\$/MWh), as % of wholesale electricity rates, and, for comparison with other proposed environmental legislation, as \$ per metric ton of CO₂ avoided (assuming avoided emissions of 1.1 tCO₂/MWh, typical for coal generation). If the total price supports (PTC+capped RECs) are less than the renewables premium, the RPS cannot be fully implemented in current conditions. Wind is used as a proxy for a general renewables premium, and solar is shown for selected states whose RPSs contain separate solar requirements and cost caps. (IL does not have a separate solar cost cap). Premiums are shown for two conditions, a typical Illinois site and the best available U.S. site. These cases are captured by capacity factors of 33% and 40% for wind and 15% and 20% for solar. Conditions applicable to the Illinois RPS are shown in regular font. Note that state cost caps are calculated using local rather than national wholesale rates. (See C.1.1 and C.1.2). For three of five RPSs shown here (CO, IL, and OH for both wind and solar), total price supports are less than the current cost premium, meaning the statutes can fulfill their goals only if renewables costs drop or electricity prices rise. For OH solar, the necessary cost drop is a factor of nearly three.

	\$/MWh	% Wholesale	\$ per ton CO ₂
<i>Wind</i>			
Premium 40% CF (33% CF)	\$25 (\$35)	60% (90%)	\$22 (\$31)
PTC 40% CF (33% CF)	\$15 (\$20)	40% (50%)	\$13 (\$18)
CO cap	\$8	20%	\$7
IL cap	\$7	18%	\$6
OH cap	\$9	26%	\$8
WA cap	\$18	45%	\$16
<i>Solar</i>			
Premium 15% CF (20% CF)	\$200 (\$140)	500% (350%)	\$180 (\$130)
PTC 15% CF (20% CF)	\$70 (\$55)	175% (140%)	\$60 (\$50)
NJ Cap (in 2016)	\$594	1500%	\$540
OH Cap (in 2024)	\$50	125%	\$45

¹ In some states, penalty payments are in turn distributed as renewables subsidies to ensure that at least some are built. These RPSs have some of the characteristics of type 2 RPSs.

² Renewables investment at a time when subsidies do not offset the current renewables premium could continue only if investors were anticipating that future increased conventional generation costs or national policy changes would later reduce their competitive disadvantage.

reductions in renewables costs or increases in electricity prices. Both changes make renewable energy more cost-competitive. In some states, increased electricity prices would also benefit RPS viability by a second mechanism that loosens costs caps. In these states (e.g. CO, OH, and WA), the cost cap is re-scaled each year to electricity prices, so that if wholesale prices rise, renewables generators not only receive greater income from the electricity they sell but are also permitted a larger total subsidy.³ Conversely, RPSs with targets high enough to affect electricity markets and depress wholesale prices – renewables operate with low marginal cost and therefore bid into markets low and become price takers (Wiser and Bolinger, 2007) – can thereby inadvertently punish renewable generators for price decreases they have brought about. These issues do not apply to Illinois, which is among the smaller number of states that peg their cost cap to a fixed value. However, rising electricity prices do aid even Illinois RPS feasibility simply by providing greater revenue to renewables generators and reducing their need for price support. We therefore consider two electricity price scenarios in the analysis of this work, one with flat prices and one with price projections at the higher end of forecasts.

3. The Illinois renewable portfolio standard

In its current form (after several amendments), the Illinois RPS will require that 25% of the state's electricity consumption come from renewable resources by the year 2025. Requirements began at 2% in 2009⁴ and will rise steadily to the ultimate goal of 25%, with targets based on the previous year's sales. (The Illinois RPS and its phase-in are described in detail in Loomis and Ohler, 2010). The phase-in is similar to that of many other state RPSs (Fig. 1), and as in other states, utilities demonstrate compliance through REC purchases. The Illinois statute contains distinctive features, however, including specific carveouts for particular renewable types and a somewhat loose preference for local generation.

The Illinois RPS contains explicit mandates for individual technologies, requiring that ~70% of the renewable portfolio be wind and that a gradually increasing fraction be solar. The Illinois RPS solar requirement begins in 2013 at a small fraction of the renewable portfolio (~0.25%) and ramps up by 2016 to 6% of the renewable portfolio, i.e. 1.5% of total electricity supply ($6\% \times 0.25$)⁵ The remainder of the portfolio may be satisfied with a typical list of qualified renewables – wind, solar (PV or thermal), landfill gas, biomass, biodiesel, or hydropower⁶ – but in practice is likely to be met mostly with wind, the cheapest renewable option in Illinois. The status of wind as the default renewable choice

means the wind carveout will likely have no significant import, but the solar requirement is significant because of the substantially larger cost of solar generation.

The Illinois statute expresses preference for local building of renewables capacity with in-state and neighboring-state restrictions, but the in-state restriction is short-lived. As of 2011, RECs may be purchased from qualified renewables not only in Illinois but also in all neighboring states (WI, IN, KY, MO, and IA). The local requirement is further weakened by an opt-out allowing the regulating agency (the Illinois Power Agency, or IPA) to permit the purchase of RECs from still other states at any time if the local resources are not in his or her judgment “cost-effective”. In practice, the IPA is granted wide discretion to void any requirement of local purchase.

The total burden on Illinois ratepayers is constrained by a “type 2” cost cap, with no limit on the price per REC but an absolute limit placed on the total cost of REC purchases. The cost cap is described in the statute in somewhat complex terms, and has a complex ramp up from 2007 to 2011, but from 2011 forward is a relatively simple absolute cap fixed at ~2% of 2011 retail electricity sales. (See previous discussion and Appendix C.2 for details.) As the renewables requirement increases over time, the maximum allowable price per REC, if implementation is complete, drops from a peak of ~\$33/MWh in 2011 to ~\$7/MWh in 2025 (and then tightens slowly over time due to increasing electricity demand, though this is a secondary effect). As Table 1 shows, these capped REC prices are significantly lower than the current renewables premium even given federal subsidies, meaning feasibility of implementation is a concern.

4. Evolution of the Illinois RPS: existing capacity and site quality

An important factor in determining the success or failure of an RPS is the quality and availability of renewable resources. We therefore analyze the amount of pre-existing capacity that can be used to meet the Illinois RPS requirements, the amount of additional capacity that would be needed, and the quality of sites on which that additional capacity would be built. We restrict our analysis to wind, since existing solar capacity is negligible in any of these states (equivalent to <1% of the 1 GW Illinois solar requirement (EIA, 2009a)) and solar insolation is roughly constant across the Midwest region. The Illinois solar requirement, if met, would be satisfied by new builds with negligible siting differences (Marion et al., 2001). The situation for windpower is different, however, both because wind speeds are spatially variable⁷ and because significant wind capacity already exists. We consider in the analysis only Iowa and Indiana in addition to Illinois because we assume they will be the dominant contributors to the Illinois requirement. These states dominate regional wind resources and the other states in the eligible region with acceptable wind potential (MO, MI, and WI) have their own large RPS requirements with local preferences. Indiana does have an RPS, but compliance is voluntary, and the Iowa RPS is such a small fraction of the state's existing capacity (3%) that it provides little competition with Illinois for REC sales.⁸

We find that existing capacity as of 2011 in these three states is sufficient to meet the majority of the Illinois RPS requirements: ~85% of the specific wind carveout and ~60% of the projected

³ Although in theory it would be possible to structure an RPS so that the cost cap was loosened with falling rather than rising electricity rates (for example, the cap could apply to the total electricity cost to the consumer rather than just to REC sales, so that lower electricity rates permitted higher REC prices), we are unaware of any legislation that does so. In all extant U.S. state RPSs we have analyzed, implementation is more feasible if electricity prices rise and less feasible if they fall.

⁴ In Illinois energy legislation, the energy year is defined as running from June to May. We use here the DSIRE convention of referring to the each electricity year by the year in which it ends (e.g. June 2008 to May 2009 is referred to as 2009). The first RECS were therefore purchased in calendar year 2009.

⁵ The statute contains an additional distributed generation requirement of 1% of the portfolio, which may be met with generation also credited as part of the wind or solar carveouts. Although the costs of distributed generation are somewhat larger than those of the utility-scale solar assumed here (roughly 40% more expensive for solar; see C.1.2), the distributed generation requirement is so small that it has negligible impact on RPS costs. We therefore neglect it in this analysis.

⁶ Hydropower is a qualified renewable under the Illinois RPS provided that it does not require the building of new dams or significant expansion of existing ones. However, the state has little hydropower potential.

⁷ The energy derivable from wind is highly sensitive to its velocity, v , scaling as v^3 . The best wind sites in Illinois have average wind speeds of 7–7.5 m/s; those of Iowa 8–8.5 m/s.

⁸ The Iowa Utilities Board encourages and permits Iowa wind generators to sell RECs out-of-state (Iowa Utilities Board Order, Docket No. AEP-07-1).

total non-solar requirements. Fulfilling the Illinois RPS requirements would still require some new wind capacity builds, with the exact total required depending on site quality. Assuming the entire unrestricted RPS is met with wind (as is the overwhelming likelihood), total required new capacity would be 5 GW on the best Iowa sites, 11 GW if the RPS were restricted to Illinois, and a still greater amount if site quality declined as builds progressed.⁹ Since new generation facilities are rationally built on the most favorable available sites, investors must turn to less ideal locations as builds progress, lowering electricity yields and resulting in higher costs per unit of electricity generated. This “site-depletion” can lead both to increased total required capacity and to higher generation costs (and effective renewables premiums) from increasingly poor siting. We therefore analyze site quality in the three states that are the most likely source of Illinois REC sales to forecast the location and cost of future wind capacity builds.

Because this work is an “endmember analysis”, we consider the most optimistic case, in which exhaustion of locations is the only driver of sub-optimal siting and there are no other constraints on wind farm siting. In reality, access to transmission lines and other infrastructure is likely to distort the selection of wind sites and result in higher wind costs. The use of optimistic assumptions means that our calculation of conditions for RPS feasibility (Section 4) yields the minimum necessary renewables cost decreases that could allow fulfillment of the Illinois RPS. Including additional site restrictions would deepen the necessary cost reductions and strengthen the conclusions of our analysis. In a national study the EIA concluded that suboptimal siting driven by transmission limitations would be relatively insignificant to nationwide wind costs [3], but the issue could usefully be further studied for Illinois.

Wind site quality in Iowa, Illinois, and Indiana has been extensively modeled as part of the Eastern Wind Integration and Transmission Study (EWITS), sponsored by the U.S. Department of Energy (Brower and Corbus, 2010). The study is itself based on an analysis of wind speeds known as the Eastern Wind Dataset (Corbus et al., 2010), performed by AWS Truepower with coordination from the National Renewable Energy Laboratory. The Eastern Wind Dataset is a 3-year simulation of 10-minute wind speeds generated with a mesoscale model (two kilometer spatial resolution) driven by reanalysis input from the NCAR-NCEP Global Reanalysis and the North American Regional Reanalysis. These wind speeds are used in EWITS to estimate site quality in terms of capacity factors, i.e. the ratio of estimated actual power output to name-plate power for a model wind turbine installation. (While the name-plate power or installed capacity is simply a measure of the size and number of turbines built, the actual electricity those turbines generate depends on the wind speed distribution at each site.) We use the EWITS capacity factors in our analysis, but do not use the estimates of potential wind farm power output subsequently derived from them. The power output estimates are based on a modeled turbine spacing and therefore installed capacity per area that appears excessively high, exceeding that of existing wind farms in the three states more than threefold (Denholm et al., 2009). (See Appendix C.1.1 for further discussion). We therefore use the surveyed turbine spacings of Denholm et al. (2009) and assume that there is some error in the EWITS. Note that this choice does not affect the comparison of relative site quality.

⁹ Existing capacity in the three states is already 6.7 GW, with the bulk in Iowa (3.7 GW) but sizable amounts also in Illinois (1.8 GW) and Indiana (1.2 GW). The total 2025 installed wind capacity required by the Illinois RPS is, depending on site quality, ≈ 8 –10 GW for the wind carveout alone and 10–14 GW including the unrestricted requirement.

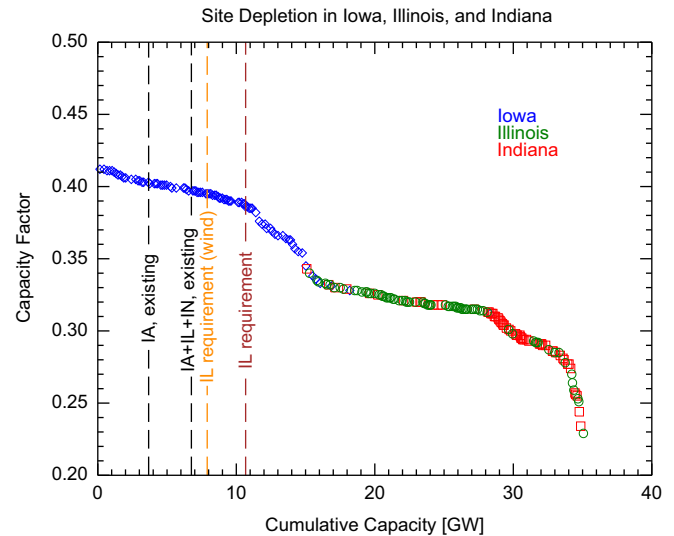


Fig. 2. Estimated capacity factors for new wind generation installations vs. total installed wind capacity in Illinois and the two most wind-endowed neighboring states (Iowa and Indiana) permissible under the Illinois RPS. Since capacity factors directly factor into profitability, sites with higher capacity factors will be (or have been) built on first; as wind penetration grows, marginal capacity factors decrease. Capacity factors and output are determined as described in the text. Vertical lines denote existing capacity in Iowa, existing capacity in the combined three states, and capacity required to meet the Illinois RPS non-solar requirement. The requirement is calculated as described in the text (and Appendix C.1.1) and refers to the current statute. Existing capacity in the three states is sufficient to meet 60% of the total non-solar Illinois RPS requirement (and $\approx 85\%$ of the wind-specific requirement). Note that for future builds, the worst plausible wind sites in Iowa are comparable to the best sites in Illinois or Indiana, suggesting that economics would drive future builds to Iowa.

Even with this adjusted estimate of site capacity, Illinois, Iowa, and Indiana have more than sufficient wind potential to meet the Illinois RPS using only wind sites currently considered suitable for commercial wind installations (Fig. 2). Indeed, site depletion is negligible regardless of which state windpower would be sited in. Each state is able to meet the new builds requirement for the Illinois RPS on sites with capacity factors dropping only slightly (34 \rightarrow 30% for IL and IN and 41 \rightarrow 38% for IA). However, Iowa sites are clearly superior to those in Illinois or Indiana, meaning that under the legislation as currently written, in the absence of transmission constraints we would expect the majority of the wind installations stimulated by the Illinois RPS to be built in Iowa. The initial terms of the legislation, with an Illinois-only preference, do suggest that a part of the legislative motivation was in-state job creation. It seems possible then that the Illinois legislature may revisit the siting requirements as evolution of the RPS becomes clear. In the remainder of analysis we therefore consider cases both of the legislation as it currently stands (with wind builds to occur in Iowa) and also of a potential future amendment that reinstates the in-state requirements (so that wind builds occur in less wind-endowed Illinois).

5. Evolution of the Illinois renewable portfolio standard: renewables premium versus the cost cap

While the lack of site depletion effects is helpful for RPS implementation in not driving renewables costs higher, fulfilling legislative goals would require actual decreases in renewables premiums. In the following two sections we determine the conditions that would permit complete implementation of the Illinois RPS, first by comparing the evolving cost cap with the REC prices necessary to support investment at current renewables

costs (in both electricity price scenarios outlined), and then by computing the necessary renewables cost drops.

Predicting the evolution of Illinois REC prices under the cost cap must require some assumptions, because although the total cost cap is set by the terms of the RPS legislation (Section 3), the available subsidy per unit of renewable electricity in conditions of fulfillment of RPS requirements depends on the amount of renewables generation required, which in turn is set by electricity demand. We assume that demand grows at an annual rate of 1% from reported IL electricity sales in 2009 (EIA, 2009a), consistent with EIA expectations (EIA, 2011b). With this assumption, the mean REC price allowed under the cost cap grows from its initial statutory limit of \$25/MWh in 2008 to \$33/MWh in 2011 as a loosening cap outpaces growth in renewables requirements, and then steadily drops after 2011, when the cap is fixed but requirements still grow, to a 2025 value of \$7/MWh. Both the statutory increases in renewable portfolio fraction and (secondarily) the growing volume of electricity sales produce this gradual tightening of the available subsidy per unit of renewable electricity.

Estimating the necessary subsidy needed to drive investment in new renewables installations also requires assumptions, even when using current renewables premiums, because of the details of financing of renewables installations and the complicated nature of the requirements for the Illinois RPS. The necessary REC prices for the wind and solar carveouts in the Illinois legislation can be derived from current renewables premiums for the respective technologies, but the remaining ~24% of the RPS can be met with any eligible technology. While wind is currently the cheapest renewable (EAI, 2011a), in past years the unconstrained RECs have traded at an ≈65% discount to wind-specific RECs, and we optimistically assume that this differential persists.

To determine the wind premium, we first estimate wind costs by tallying installation and maintenance costs using information from Wisler and Bolinger (2010) and estimating capacity factors as per Fig. 2. Assumptions relevant to all cost estimates (both wind and solar) are detailed in Appendix C and include a contribution from integration costs (provision of backup generation capacity) but not transmission costs (which may not be borne by the renewables generators); financing via a 20-year loan at 6% interest rate; and importantly that the PTC is renewed and remains in force. We then estimate wind revenues by assuming wind-generated electricity is sold at the current Illinois mean wholesale electricity rate of \$35/MWh (3.5 cents/kWh) (Wisler and Bolinger, 2011; ComEd, 2011). The resulting wind premiums inclusive of the PTC, and therefore the necessary REC prices, are \$15/MWh and \$20/MWh for stimulating investment in Iowa and Illinois, respectively. (Note that these premiums are slightly higher than the nationwide numbers of Table 1 because of Illinois' low electricity prices, which make the state less favorable for renewables. See Appendix C.1.1 for full derivation and further discussion.)

Solar premiums are more difficult to estimate even at present, because the cost of solar experienced a significant drop in 2011. We use two values in this analysis. Primarily, we use third-quarter 2011 costs as tracked by the SEIA (2011) (\$3.45/W_p install cost). These costs are broadly consistent with actual power purchase agreements (PPAs) signed in 2011 Q4 in California (California Public Utilities Commission, 2012). Costs are still in flux, however. Recent California solar generation contracts suggest that the cheapest solar projects may now achieve costs as much as ~30% lower than the 2011 SEIA values (The California Energy Commission, 2012; Barbose, 2012), though some part of those low projections may be due to temporary oversupply or to subsidies to panel manufacturers by exporting nations. The low

recent costs may therefore be temporary (negated by reduction of oversupply or punitive tariffs), but we optimistically include them in this analysis as a lower bound on uncertain current solar costs. In both cases, values used are those for utility-scale generation only, because costs and solar premiums are lowest for this size class. (Small-scale residential installations are nearly twice as expensive, although that difference is somewhat offset by the fact that residential generators in Illinois are permitted net-metering, i.e. to essentially receive retail rather than wholesale prices. See Appendix C.1.2 for full derivation of costs and further discussion.)

With these assumptions, the REC price needed to drive solar investment in Illinois becomes \$80–\$130/MWh, 5–9 times that needed to support wind. Regardless of the uncertainty in solar costs, it is evident that current necessary price supports of \$15/MWh for wind, \$10/MWh for unrestricted renewables, and \$80–130/MWh for solar power do not permit fulfillment of an RPS with an eventual \$7/MWh average cost cap. Successful implementation of the Illinois RPS requires a significant change to the economic landscape for renewable power generation.

The infeasibility of the Illinois RPS in the current cost landscape is also readily seen by comparing the tightening cost cap to the available price supports (Fig. 3). As the RPS requirements ramp up, the cost cap tightens, until by 2015 the available subsidy no longer exceeds the renewables premium. The discrepancy between available subsidy and needs is exacerbated by the ramp-up of the solar requirement, but even amending the RPS to remove the solar requirement would not make full implementation feasible in the current cost landscape. Without the solar requirement, the cap would still be “broken” – the mean necessary REC price for full implementation would exceed the permissible cap – by 2017. Amending to restrict wind to Illinois would

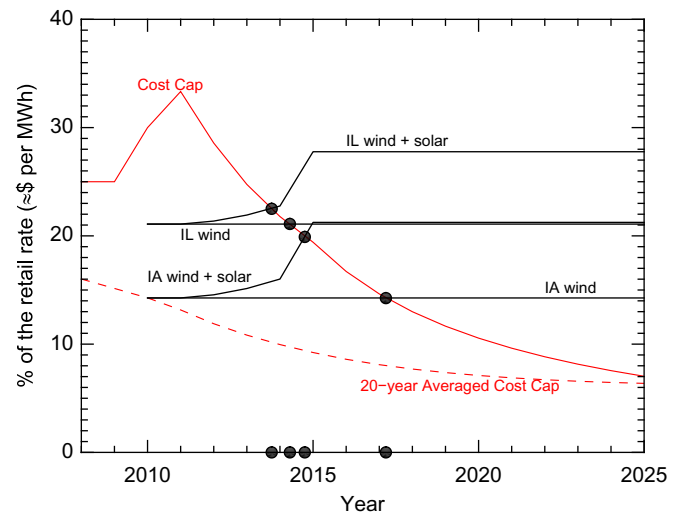


Fig. 3. The Illinois cost cap (red), 20-yr averaged cap (dashed red) and necessary mean REC price for RPS fulfillment under various scenarios (black) as a function of time. Scenarios include possible amendments to the RPS to restrict wind to Illinois and to remove the solar carveout. The necessary REC price is estimated using current wind and solar costs and electricity prices; see Appendices C.1.1 and C.1.2. The cap initially increases as its statutory loosening outpaces the ramp-up of RPS requirements, but then decreases from 2011 when the cap is fixed but renewables requirements continue to grow. The times when necessary REC prices exceed the cost cap are marked with black dots both on the cost curves and on the x-axis below. These mark times when new generators would be unable to recover their annualized costs even in the first year of operation. Even in the most favorable scenario (solar requirement removed, permission to use Iowa wind remains), the necessary REC price exceeds the cap by 2017. The 20-yr averaged cap, which governs the lifetime profitability of new builds, is lower and exceeded necessary REC support only prior to 2010.

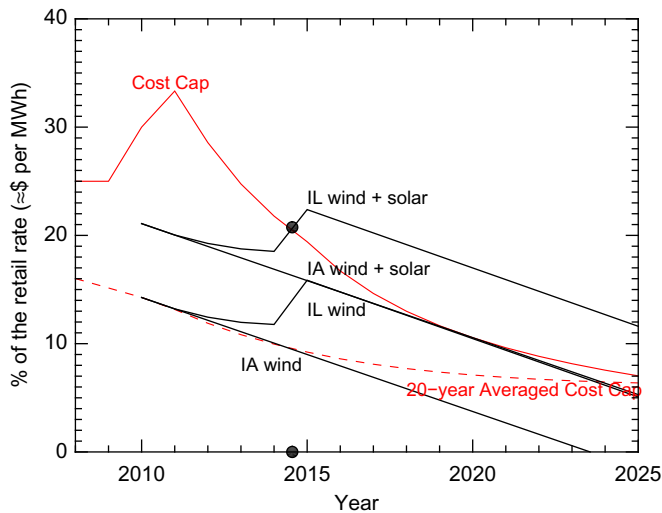


Fig. 4. As in Fig. 3: the IL cost cap (red), 20-yr averaged cap (dashed red) and mean REC rate under various scenarios (black) as a function of time, only here with wholesale electricity prices rising linearly from the current value of \$35/MWh to a peak of \$55/MWh in 2025. The strong increase in wholesale rates means that necessary REC support exceeds the instantaneous cap only if wind is restricted to Illinois. Under the terms of the current statute, new builds are currently unprofitable in conditions of RPS fulfillment (the renewables premium exceeds the 20-yr averaged cap) but would become profitable in 2024.

make fulfillment significantly more difficult, breaking the cap by 2014.

In fact, the cost cap is already “broken” in a more relevant sense: already in 2011, the cost cap projections averaged over the lifetime of a renewables facility (20 yrs) do not provide the subsidy necessary for investors to recover their costs in a situation of full implementation (dashed line in Fig. 3). If renewables investors are rational, construction of new capacity will then continue only at a rate lower than legislative goals. This legislative failure may not be apparent for another decade, though, since oversupply of capacity will keep REC prices low. Existing capacity in IL, IA, and IN is sufficient to meet projected Illinois RPS requirements until 2020, and barring unforeseen competition for RECs from other state RPSs, only then will new capacity requirements force REC prices to rise.

The previous analysis assumed current electricity prices; we repeat the analysis for the scenario of a 60% increase in electricity prices by 2025 described previously (Fig. 4). The rising electricity prices mean that Iowa wind generation would reach grid parity by 2024 presuming the PTC is renewed (henceforth “PTC grid parity”) and require no subsidy. The entire RPS subsidy would then be devoted to the solar requirement, allowing the RPS to achieve full compliance (though after a brief period of non-compliance between 2020 and 2024, when new builds could resume).

6. Evolution of the Illinois RPS: necessary renewables cost evolution

RPS success can be ensured by various combinations of three factors: decrease in solar costs, decrease in wind costs, and increase in electricity prices. In this section we explore combinations that would permit fulfillment of legislative goals, i.e. that would provide sufficient incentive for renewables builds with an ultimate average cost cap of \$7/MWh. We show the wind and solar costs necessary for RPS fulfillment at current electricity prices in Fig. 5 and at a series of increasing electricity prices in

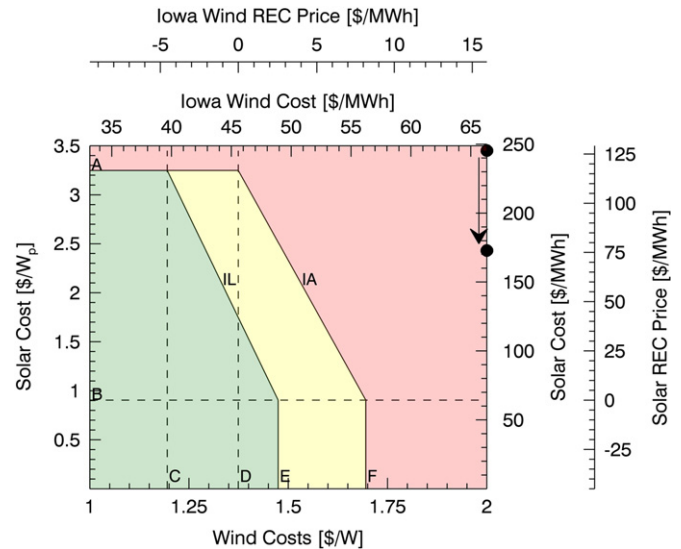


Fig. 5. Wind and solar costs needed for success of the Illinois RPS given current electricity rates, inclusive of support from the PTC. Required costs are determined by setting the mean REC rate equal to the \$7 per REC cap and solving for the necessary solar cost as a function of the wind cost. The parameter space which leads to RPS failure is marked in red; that of success with an Illinois-only wind restriction in green; and that of success with Iowa wind but failure with an Illinois restriction in yellow. Points of interest are marked with letters along both axes. Axes show both install costs (in \$/W full capacity for wind and \$/W_p for solar), the resulting levelized cost of electricity and expected REC prices (post-PTC premium), assuming capacity factors typical of the Midwest for solar and Iowa for wind. Since the current cost of solar is uncertain, we mark the likely range with an arrow. All are shown here as true costs, without the PTC. At current renewables costs (upper right corner), the RPS would clearly be in failure, even were solar costs at the lower edge of current estimates (tip of arrow). If solar install costs are above \$3.2/W_p (A), the solar carveout would break the cost cap on its own even were wind at PTC grid parity. Wind would reach PTC grid parity at \$1.2/W for Illinois wind (C) or \$1.4/W for Iowa wind (D), drops of 40% and 30% from current costs. For solar to reach PTC grid parity, solar install costs must fall to \$0.90/W_p (B), a drop of 75% from 2011 Q3 SEIA estimates. If solar did reach PTC grid parity, or if the solar carveout were removed and all subsidy could go to wind, the necessary wind install costs would be \$1.4/W with an Illinois restriction (E) and \$1.7/W without (F), reductions of 25% and 15%. If neither technology is at PTC grid parity, the necessary cost reductions trade off against each other (diagonal line), although not with a 1:1 slope.

Fig. 6. In Fig. 5, conditions of RPS success even with Illinois wind are marked in green, of success with Iowa wind in yellow (plus green), and of failure in red. Although the PTC is also a major factor in RPS success, we do not consider cases in which the PTC is not renewed, as RPS success is almost prohibitive without it. Because current solar costs are somewhat uncertain, we have marked both the SEIA 2011 Q3 cost and a lower estimate based on unpublished estimates of the lowest cost 2011 projects (Barbose, 2012; See Appendix C.1.2)

If electricity rates remain flat, achieving success of the Illinois RPS as written would likely involve substantial decreases in both solar and wind costs (Fig. 5). In any scenario of success, wind costs must drop by at least 15% to \$1.7/W install cost.¹⁰ This decrease is required even if solar achieved PTC grid parity. If instead Iowa wind achieved PTC grid parity, solar must drop by at least 6% from SEIA estimates (to \$3.2/W_p). PTC grid parity for either technology is far from certain, however, as it would require reductions of 30% for Iowa wind and 75% for solar (to \$1.4/W and \$0.9/W_p, respectively).

In more plausible success scenarios where both technologies continue to require additional subsidy from REC sales, their necessary

¹⁰ This install cost value assumes cost reductions are proportional in both installed and O&M costs.

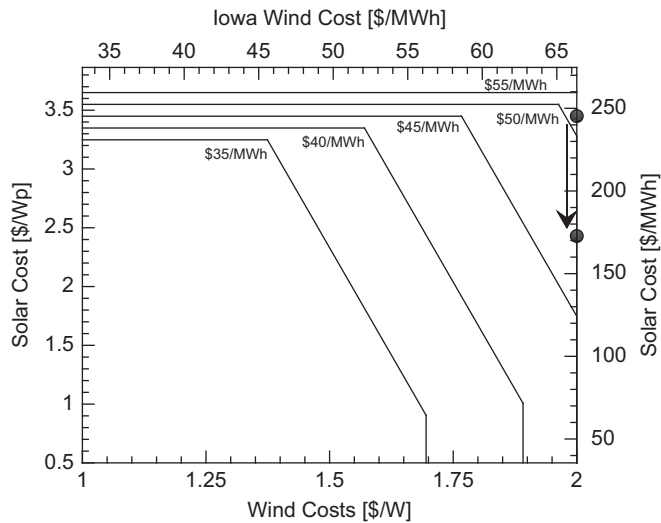


Fig. 6. Wind and solar costs needed for success of the Illinois RPS, as in Fig. 5 but at increasing wholesale electricity prices. For every \$5/MWh increase in prices, the allowable wind install costs increase by 10% (\$0.2/W). If the wholesale rate hits \$55/MWh, wind reaches PTC grid parity even at current costs (horizontal line), permitting all subsidy to go to the solar carveout. In that case, the Illinois RPS goals are achievable even at the higher end of current estimates of solar costs. If solar costs lies at the lower end of those estimates, the Illinois RPS could be fulfilled given a rise in electricity prices of ~30% (to ~\$47/MWh).

cost decreases trade off against each other because both are included under a single cost cap. The resulting “parameter space” for RPS success is then irregularly shaped, with vertical or horizontal boundaries if one of the technologies reaches grid parity and a sloping boundary if both technologies require RPS subsidy. In this tradeoff region, drops in the cost of either technology can be viewed as freeing up RPS funding under the cost cap that can be used to support the other technology instead.

Higher electricity prices reduce renewables premiums and make the success of the Illinois RPS more feasible (Fig. 6). The benefits of higher electricity costs are stronger for wind than they are for solar, because solar costs are still so high that the bulk of solar income is subsidy and so increasing electricity prices provide a smaller relative relief from necessary support. (For utility-scale solar facilities at the SEIA 2011 Q3 costs, average solar revenue from electricity sales is only ~20% of total costs or ~25% of post-PTC costs.) For wind, each \$5/MWh increase in electricity prices reduces the necessary wind cost decrease by 10 percentage points (i.e. \$0.2/W), so that a rise of less than \$20/MWh brings wind to PTC grid parity. Were wind at PTC grid parity, each \$5/MWh increase in electricity prices would reduce the necessary solar cost decrease by only 3 percentage points (i.e. \$0.1/W_p).

Increased electricity prices do benefit solar strongly in an indirect way, however, if wind is not yet at grid parity, by freeing up cost cap dollars that would otherwise be needed to subsidize wind generation. Once wind has been brought to grid parity, further electricity rate increases have little effect on solar cost-effectiveness, but at that point conditions allow or are very near to permitting complete fulfillment of the RPS, with minimal further necessary drops in solar costs. Higher electricity prices would therefore promote RPS success largely by slashing the support necessary for wind and permitting the bulk of RPS subsidy to support the solar carveout.

7. Discussion

Some partial validation of the above analysis can be derived from considering the brief history of the Illinois RPS to date

(2008–2011). It is true that the RPS has achieved full compliance in each year since implementation, with wind REC prices consistently decreasing, from \$32.50/MWh in 2008 to \$19.78 in 2009 (Loomis and Ohler, 2010), to \$4–\$5 in 2010, and to ~\$1 in 2011 (ICC, 2010a, 2010b). These decreasing REC prices do not reflect the subsidy needed for new builds, though, but instead the condition of oversupply in the REC market, as existing capacity in eligible Midwest states is more than sufficient to satisfy the current Illinois RPS requirements. Oversupply appears to have driven the Illinois REC price down to that of the nationwide REC market (Wiser and Bolinger, 2011). A more reasonable proxy for the subsidy needed to stimulate investment is the long-term REC price given to renewables facilities that have negotiated 20-year contracts to supply RECs and electricity to Illinois utilities. The average price for bundled electricity and RECs under these agreements ranges from \$50 to \$55/MWh in 2010 for the two largest utilities in Illinois, Ameren and ComEd. Given the current wholesale electricity price of \$35/MWh, these values suggest a necessary subsidy of some \$15–20/MWh, very similar to our estimated premiums. If renewables premiums are as high as we have estimated and as the long-term REC prices suggest, then it is inescapable that the Illinois RPS cannot succeed without significant changes to the renewables and electricity cost landscape.

It is also worth reiterating that there is no plausible means of meeting RPS objectives under the cost cap in any scenario if the federal PTC is not renewed. For wind in particular, the Illinois state RPS merely tops up the subsidy of the PTC, which provides twice as much support as would 2025 capped REC sales (Table 1 and Appendix C). The same conditions hold for other states with similar cost caps. The dependence on the PTC is also significant in light of recent proposals for a federal RPS. If such a federal RPS replaces the PTC, federal REC prices would have to rise considerably over current state-level REC prices, because they would have to reflect the full cost of renewables, including the subsidy currently provided by the PTC. A cost cap on a federal RPS would therefore need to be significantly larger than current state caps to have similar feasibility of success: e.g. the necessary cost cap on the proposed 20% federal RPS would have to be 6% of the retail rate to be analogous to the 2% cap on the larger Illinois RPS.¹¹

Our analysis suggests that even with a continued PTC, the success of the Illinois RPS hinges on cost decreases for renewables that are possible but not certain. The least uncertain forecast is that of wind costs, since the wind industry is relatively mature, though that maturity also means that potential fractional cost decreases are not large. In 30 yrs of wind turbine installation from the early 1980s onwards, the cost of installed windpower steadily decreased up until 2001, then plateaued and actually increased by 25% through 2010, driven largely by increases in turbine prices (Wiser and Bolinger, 2011). That trajectory is characteristic of a maturing technology whose initial large efficiencies of scale and technological advancements have already been captured. Turbine price increases over 2001–2010 were driven by a combination of factors including supply shortages, increased materials and labor costs, and increased design complexity (Wiser and Bolinger, 2011). These factors seem to be relaxing somewhat, and installed costs decreased by ~10% in 2011. Nevertheless, cost projections from the EIA suggest that the wind premium will remain at or above current levels through 2020¹² (EIA, 2011b).

¹¹ A similar transfer of subsidy to REC prices has been seen in New Jersey, where the state solar market was supported both by a rebate program and by REC sales until 2007. When rebates were eliminated, REC prices jumped to compensate for the lost subsidy (pers. comm. with Benjamin Hunter, Renewable Energy Program Administrator with the Office of Clean Energy, New Jersey BPU).

¹² More distantly, the EIA suggests wind costs may decrease again between 2020–2035, largely after the Illinois phase-in, to bring wind near grid parity in 2035 (EIA, 2011b).

Solar costs may have more room for movement than those of wind, since the industry is less mature and both manufacturing and technology breakthroughs are possible (as suggested by the sudden drop in panel cost in 2011). The necessary solar cost for RPS fulfillment depends steeply on wind cost evolution, though. A wind cost drop of 32% puts wind in PTC grid parity, at which point the needed solar cost drop is only 6% from SEIA 2011 estimates, readily achievable (or already achieved). But with even slightly lower wind cost, the pressure on solar grows sharply. If wind costs drop only 15%, the minimum needed for RPS fulfillment, solar power costs would need to drop by 75% to PTC grid parity, a likely prohibitive requirement. The solar cost reductions in the last decade (first a steady $\sim 3\%/yr$ reduction and then an abrupt 2011 drop) have been driven largely by reduction in module prices (SEIA, 2011). Solar generation costs are now in fact dominated by installation, integration, and other expenses, with the modules themselves a secondary factor. Current estimates of module costs of $\$1/W_p$ mean that of the SEIA utility-scale costs of $\$3.45/W_p$, $\$2.45/W_p$ is taken up by non-module expenses (SolarBuzz, 2012; Sutula, 2006). For this reason caution should be applied when envisioning steep reductions in solar costs, especially on short timescales. Recent cost figures do suggest that sharp improvements in non-module costs are already occurring: best-in-industry solar costs of $\$2.50/W_p$ with an estimated $\$0.80/W_p$ module cost imply that some firms have achieved an over 40% reduction in non-module expenses (SolarBuzz, 2012; Barbose, 2012). Nevertheless, solar would achieve PTC grid parity only with total costs less than $\$1/W_p$, highly unlikely in the timeframe of the Illinois RPS.

In summary, while the Illinois RPS may prove feasible through continued reductions in wind and solar costs and/or an unforeseen rise in wholesale electricity rates, it is also possible that the legislation may not be fully implemented as written. We note that the combination of price supports for both solar and wind under a single cost cap exacerbates the danger of non-fulfillment since it allows the technologies to have pernicious effects on each other: any technology that does not meet cost expectations will curtail deployment of the other. If cost reductions in either technology do not materialize, REC markets would remain high, since investment could not proceed otherwise, and total spending would be driven up to the legislative cost cap, triggering a freeze on the renewables requirement. Illinois ratepayers would then find themselves paying a higher subsidy per unit of renewable energy than they had intended. In this failure mode, both individual subsidy levels and the overall outcome may be significantly out of line with voters' and legislators' expectations. It is also useful to note that "meeting cost expectations" has differing meaning for solar and wind. Because windpower is closer to PTC grid parity, equivalent fractional drops in costs disproportionately alter the relative levels of support that wind and solar need. In the present cost landscape, meeting the final Illinois RPS wind and unrestricted requirement would take twice the subsidy as would meeting the final solar carveout. In virtually all scenarios of RPS success, though, the subsidy absorbed by the solar carveout exceeds that provided to the remaining 94% of the renewable portfolio.

8. Conclusions

Analysis of the conditions that allow success of the Illinois RPS highlights the danger of combining multiple objectives in a single piece of legislation. The different objectives that can underlie RPS legislation may be in conflict, and that conflict can result in unforeseen and undesired consequences. (See also Loomis and Ohler, 2010.) The desire for lower prices can be in conflict with the goal of local jobs creation. Local job stimulation from the Illinois RPS is likely to be quite small, as existing wind farms in IL,

IN, and IA alone can satisfy the Illinois RPS for a decade, and under current statutory language, new builds thereafter would almost certainly occur in more wind-endowed Iowa. The evolution of the Illinois RPS then would largely involve transfer of Illinois ratepayer dollars to Iowa (though longer term, wind projects in Iowa may benefit the Illinois economy indirectly by boosting Illinois manufacturing, Carson et al., 2010). Restricting qualifying renewables to new facilities would however cause currently depressed REC prices to rise, and restricting new builds to Illinois would again raise REC prices and hinder RPS success under its cost cap. The local-vs.-cheap conflict occurs in the case of solar as well. Although there is no meaningful difference in insolation among the Midwestern states currently eligible for solar REC sales under the Illinois RPS, restricting eligibility to the Midwest and excluding sunny states such as AZ, NV, and CA makes solar power some 30% more expensive than if drawn from the best solar sites. Removing siting restrictions on qualifying solar facilities would make fulfillment of the Illinois RPS more feasible, but at the tradeoff of transferring funds out of state.

The objectives of helping renewables industries and mitigating climate change may also be in conflict. Because solar electricity generation is substantially more expensive than windpower at present, and therefore requires higher price support per unit of energy, distributing subsidy to solar generators does not produce the maximal reduction in carbon emissions. The equivalent carbon price needed to support Midwestern solar energy, even after the PTC, is currently nearly $\$120/\text{ton CO}_2$ (Table 1). For a given amount of spending, the greatest climate change benefit in the short term is obtained by supporting the most cost-effective carbon-free generation technology, i.e. windpower (or possibly carbon sequestration, which is not covered by the RPS). In the long term, of course, the additional solar builds driven by solar requirements in state-level RPSs may help the industry reduce costs, and this assumption likely forms part of the underlying legislative motivation.

Finally, the co-mingling of requirements for different technologies under a single cost cap means that either of the technology carveouts in the Illinois RPS can throw the legislation into failure mode if its costs do not drop sufficiently, freezing requirements for all renewables. This destructive interaction is the most easily addressable conflict inherent in the Illinois RPS, however, as it can be eliminated simply by amending the statute to divide the cost cap between the two technology requirements.

The similarity of state RPSs suggests that the Illinois experience is not likely to be unique. The similar timescale for implementation of most state-level RPSs implies that many states may face similar difficult decisions in upcoming years as their cost caps tighten. The Illinois RPS can therefore offer lessons that help guide not only expectations of existing RPS evolution but also design of future legislation. Most simply, legislators can wherever possible attempt to insulate overall legislative success from the failure of individual assumptions and goals. Independent cost caps on separate technology requirements are an obvious solution that avoids pernicious effects of one technology on another. More broadly, it is useful to be clear on the relative importance of different objectives and to transparently evaluate the inevitable tradeoffs. Analysis both of conditions necessary for success and of the likely evolution of the RPS in failure mode should be part of the legislative design process. If RPS success requires substantial cost decreases in renewables, it is worth evaluating whether the RPS can help bring about those decreases. Most importantly, once the cost landscape is made clear and legislators and ratepayers are unified on goals for renewable energy, the legislation should be crafted to permit those objectives to be met. It is possible that an RPS may have some indirect benefits even if it does not meet its renewables

target: e.g. changes to planning and zoning laws, creation of REC markets, and acknowledgement of transmission problems (Ohler and Radusewicz, 2010). Nevertheless, the key design criterion should be maximizing the likelihood of the success of the legislation, since an RPS that fails can result in misallocated outlays with suboptimal environmental benefit and loss of public support for renewable energy.

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Appendix A. Acronyms

Acronyms and selected terms used throughout the paper are given in Table A1.

Appendix B. Major intrinsic assumptions in endmember feasibility analysis

Assumptions made throughout the paper is given in Table B1 and renewables premium input summary is given in Table B2. To reproduce figures with alternate assumptions or for other states, see rpscalc.rdcep.org.

Appendix C. Calculations of renewables premiums and cost caps

C.1. Renewables premiums

At present, the cost of generating electricity from most renewable technologies exceeds that of generating electricity from

Table A1
Acronyms and selected terms used throughout the paper.

Name/abbreviation	Meaning <i>Comment (if applicable)</i>
Ameren	The second largest utility in Illinois
ARES	Alternative retail electric supplier <i>Any non-municipal electricity provider aside from Ameren and ComEd</i>
ComEd	The largest electric utility in Illinois
DOE	Department of Energy <i>Referenced for electricity statistics</i>
DSIRE	Database of State Incentives for Renewables and Efficiency <i>Compiles information on RPS legislation in Illinois and in other states</i>
EIA	Energy Information Administration <i>Referenced for electricity statistics</i>
EU	Illinois Electric Utility (Ameren and ComEd)
EWITS	Eastern Wind Integration and Transmission Study <i>Model wind farm output used to evaluate site quality in IL, IA, and IN</i>
GW	Gigawatt (10 ⁹ W)
IEA	International Energy Agency <i>Referenced for renewable costs</i>
IPA	Illinois Power Agency <i>The Illinois RPS regulating agency</i>
MWh	Megawatt-hour
NCAR	National Centers for Environmental Prediction <i>Provided wind speed inputs for the EWITS model</i>
NCEP	National Center for Atmospheric Research <i>Provided wind speed inputs for the EWITS model</i>
NREL	National Renewable Energy Laboratory <i>Referenced for renewable statistics</i>
O&M	Operations and Maintenance Costs
PPA	Power purchase agreement <i>Long-term electricity purchase contracts between utilities and generators</i>
PTC	Production Tax Credit
ITC	Investment Tax Credit
PV	Photovoltaic
REC	Renewable Energy Credit <i>Subsidy and enforcement mechanism for RPSs</i>
RPS	Renewable portfolio standard <i>A renewable electricity requirement</i>
SEIA	Solar Energy Information Agency
W	Watt
W _p	Watt peak <i>Solar panel capacity defined with 1000 W/m² insolation</i>

Table B1

Assumptions made throughout the paper.

Assumption	Effect vs. best estimate
<i>Optimistic</i>	
PTC is renewed	Continues 30% effective reduction in renewables installed costs
RPS is met by lowest-cost renewables	Makes the RPS easier to fulfill within the cost cap
Neglect the 1% distributed generation carveout	Makes the RPS easier to fulfill within the cost cap
Neglect renewables siting restrictions due to transmission limitations or access to infrastructure	Decreases renewables costs
Unrestricted RECs trade at 65% of wind REC price	Makes RPS easier to fulfill within cost cap
Steepest plausible increase in electricity prices when considered	Decreases renewables premium
No out of state REC competition	Keeps REC price low, easier to meet RPS under cap
Renewables receive 20-year loans at a 6% interest rate	Low rate decreases renewables costs
Wind generators receive the mean wholesale rate	Decreases renewables premium slightly
All solar is utility scale	All solar facilities have lowest solar premium
<i>Pessimistic</i>	
Wholesale price increases are equal in \$ value for wind and solar	Solar would be slightly more cost competitive if the increase were proportional
Wind integration costs borne by renewable generators	May increase renewables premiums slightly
<i>Best estimate</i>	
Electricity growth rate of 1% per year	
Wind RECs supplied by IL, IN, and IA	

Table B2

Renewables premium input summary.

Description	Input	Levelized cost (if applicable)
<i>Wind</i>		
Installed cost	\$2/W	\$50/MWh (IA) & \$60/MWh (IL)
O&M	\$10/MWh	\$10/MWh
Integration cost	\$5/MWh	\$5/MWh
Financing	6%, 20 yrs	(9% amortization)
Capacity factor	40% (IA) & 33% (IL)	
Wholesale value	\$35/MWh	
<i>Utility scale solar</i>		
Installed cost	\$3.45/W _p –\$2.50/W _p	\$236/MWh–171/MWh
O&M	\$0.012/W _p /yr	\$9/MWh
Integration cost	\$0/MWh	\$0/MWh
Financing	6%, 20 yrs	(9% amortization)
Capacity factor	15% (Midwest)	
Wholesale value	\$45/MWh	

conventional fossil-fueled sources. In this paper we define the “renewables premium” as the excess cost of renewables generation over the market value of that electricity (which is largely set by conventional generation). The renewables premium is then the additional subsidy that must be received by renewable investors in order to drive investment in the renewables industry at current prices. Note that the relevant factor for investors is the renewables premium over the lifetime of the facility; investors may build in conditions of insufficient current subsidy if they expect future increases in electricity prices that effectively reduce the renewables premium.

The renewables premium is necessarily technology-specific, not only because of differing costs for the different renewable technologies but because of differing prices received for the sale of electricity generated. Although electricity is an entirely fungible product – once it is on the grid, electricity produced by a wind farm cannot be distinguished from that from a coal plant – individual generators do not necessarily receive the mean wholesale price because electricity may be sold on an hourly basis, with prices varying both diurnally and seasonally. Some renewables also have different modes of sale (long-term contracts or net metering for solar).

The renewables premiums for a given technology is then given by

$$RP_i = C_i - P_i$$

where RP_i is the renewables premium for renewable technology i , C_i is the cost of generation, and P_i is the market value of the

electricity produced. All these terms are normally expressed in units of \$/MWh.

The cost C_i is the levelized cost of generation, given in current dollars, defined as

$$\frac{(\text{install cost})(\text{amortization}) + (\text{fixed O\&M})}{(\text{h/yr})(\text{capacity factor})} + (\text{marginal O\&M}) + (\text{integration cost}).$$

The first term describes fixed costs, divided by the total energy produced; the latter two terms describe costs that are incurred as a function of energy produced. The amortization factor accounts for the cost of financing upfront expenses and is set by the interest rate and loan period. (Amortization is the process of repaying a debt over time in regular installments). The amortization factor stated here is the percentage of the loan amount (install cost) that must be paid annually. Fixed O&M costs are those which are incurred regardless of whether or not generation occurs. Since they are typically given in the literature as annual costs per unit capacity, they are not multiplied by an amortization factor. The (h/yr) factor translates an annual cost in \$/MW per year into \$/MWh.

The PTC and ITC (“PTC” throughout this paper) are federal-level subsidies that effectively reduce the cost of renewables generation by reimbursing qualifying renewable projects for up to 30% of the initial construction cost. The ITC, originally enacted in 2008, offers qualifying renewables (which include small wind and solar) a tax credit of 30% of costs.¹³ The PTC, originally enacted as part of the Energy Policy Act of 1992, initially offered qualifying renewables (which include all wind and solar) a somewhat less advantageous subsidy of a tax credit per unit of energy generated of \$22/MWh for wind and \$11/MWh for solar for the first 10 years of operation only. The PTC has been renewed and modified numerous times since 1992, however, and its most recent incarnation (via The American Recovery and Reinvestment Act of 2009) allows eligible facilities in service prior to 2013 to opt to receive the more favorable ITC subsidies instead. In practice all generators take this option. The combined effect of the PTC/ITC in their current forms is that all wind and solar facilities receive a 30% subsidy, with new, large wind facilities (> 100 kW capacity)

¹³ The American Recovery and Reinvestment Act of 2009 modified the ITC by allowing generators to receive a Treasury Department grant rather than a tax credit.

receiving it through 2012 and solar facilities through 2016, when the ITC itself expires. Throughout this paper we assume that both statutes will be extended in their current form through 2025, because the analysis would be moot otherwise: Illinois and other state RPSs almost certainly cannot succeed without the federal support. We estimate the value of the PTC (in \$/MWh) for each technology (wind and solar) simply by taking the product of the installed cost, the amortization rate, and the PTC fraction (30%) and dividing by the annual energy produced. That PTC value is then subtracted from the estimate of generation cost C_i .

We discuss below the remaining inputs and assumptions used to derive the renewables premiums for wind and solar used in this work. Throughout this paper, when parameters are uncertain we adopt the plausible assumptions that most favor renewables.

C.1.1. Wind premium

Windpower capacity factors. Calculating the cost of windpower requires estimating both the cost of installed generation capacity and the amount of power produced by that installed capacity. Total generation cost per actual unit of electrical energy produced is installed capacity cost multiplied by a “capacity factor”: the actual output of a generator over a period of time divided by the output if the generator were always operating at full nameplate capacity. Capacity factors of existing facilities in the United States range from 20% to nearly 50% (Wiser and Bolinger, 2011). For a given RPS requirement of wind electricity sales, a lower capacity factor would lead to higher costs per unit of electrical energy generated (and so higher necessary REC support) and a larger total necessary volume of installed capacity to meet the RPS target.

The volume of total wind REC sales under the Illinois RPS is fixed by statutory requirement and by an assumption of electricity use growth rates. (Growth rates matter since the total renewable generation ultimately required by the Illinois RPS is given as a fraction of total electricity sales). Illinois retail sales in 2010 were 1.4×10^8 MWh, and we assume a growth rate of 1% per year, consistent with EIA expectations (EIA, 2011b). The non-solar REC sales requirement in 2025, which we assume is filled by wind, is then 4×10^7 MWh, i.e. an actual wind generation rate of 4.6 GW. Given capacity factors of 40% (typical for Iowa, whose best wind sites have wind speeds of 8–8.5 m/s), the total required capacity would be 11 GW. If REC sales were restricted to Illinois, with best capacity factors of 33% (average wind speeds of 7–7.5 m/s), the total required capacity would be 14 GW. Since existing capacity in the three states likely to contribute wind RECs to the Illinois market is 6.7 GW, new builds would certainly be needed for RPS fulfillment. (The bulk of existing capacity is in Iowa, with 3.7 GW, but sizable amounts are in Illinois, at 1.8 GW and Indiana, at 1.2 GW.)

Average capacity factors could decline as wind builds progressed if site quality decreased. In the wind-site analysis of Section 4, we considered the impact of the distribution of site qualities on the volume and cost of required new wind capacity under the Illinois RPS. That analysis led to the conclusion that site degradation does not significantly impact capacity factors for new builds in any given state (of IL, IA, and IN). We therefore simply adopt two different capacity factors to represent wind typical of Iowa and those typical of Illinois. The values of 40% and 33%, respectively, are the average capacity factors for the respective sites given the projected build volumes. With these values, the volume of required new builds is $11 \text{ GW} - 3.7 \text{ GW} - (1.8 + 1.2) (0.33/0.40) \text{ GW} \approx 5 \text{ GW}$ under the current Illinois statute and $13 \text{ GW} - 1.8 \text{ GW} \approx 11 \text{ GW}$ were wind REC sales restricted to Illinois facilities.

In the analysis we use capacity factors from the EWITS, but not the EWITS estimates of actual power output from model wind

farms. To calculate the capacity factor, EWITS uses the distribution of simulated wind speeds, averaged on 10-min intervals, to produce a distribution of turbine power outputs, for three possible turbine choices. The average electrical power produced, and therefore the capacity factor, is then extracted from the power output curve of the optimal turbine choice for the site in question. Finally, the EWITS assumes a turbine spacing and estimates a total power output per area of wind farm. Assumed turbine spacings appear excessively high, however. Average EWITS modeled wind farm installed capacity per area in IL, IN, and IA are 13.9 ± 0.3 , 11.9 ± 0.4 , and 11.2 ± 0.3 W/m², respectively. Actual wind farms in IL, IN, and IA compiled by Denholm et al. (2009) average 4.0 ± 0.4 , 2.4 ± 0.6 , and 3.3 ± 0.5 W/m², respectively (Denholm et al., 2009). It is possible that spacing in existing farms is unnecessarily broad, but a 2010 NREL study of windpower potential assumed an installed capacity per area for Illinois of only 5 W/m² (Elliot et al., 2010). Note that the rule of thumb of turbine spacing of 5 rotor diameters perpendicular to the prevailing wind and 10 rotor diameters along it for a typical 2 MW turbine yields a capacity density of 5.4 W/m².

Windpower generation costs. In this section we consider those generation costs that are independent of site quality. The cost of wind generation (C_{wind}) is dominated by the cost of wind turbines, but turbine installation, operations and maintenance, and grid integration contributions are not negligible (Wiser and Bolinger, 2011). In this work wind install costs are taken as \$2/W of peak capacity, as estimated for the U.S. in 2011 by Wiser and Bolinger (2011) at Lawrence Berkeley National Laboratory, who assembled a historical record of U.S. wind costs from sources such as the EIA, FERC, SEC, state-level public utilities commissions, Windpower Monthly magazine, and the AWEA. The 2011 estimate represents a 10% drop from 2010 costs. Over the past three decades, U.S. wind install costs decreased from ~\$5/W in the 1980's to a low of \$1.5/W in 2000, and then rebounded to nearly \$2.2/W in 2010 (costs are stated in dollars per watt of name-plate capacity). The price increases of the last decade were driven largely by turbine prices which were raised by supply shortages, increased material costs, increased design complexity, and manufacturers' unwillingness to tolerate the low profit margins of previous years (Wiser and Bolinger, 2011). Some of these upward price pressures are relaxing, but it is not clear that turbine prices will fall back to the 2000 low (a 30% drop).

We assume here that capital expenditures on wind installations are financed by a 20-year loan at an annual interest rate of ~6%, making the amortization rate 9%. A 6% interest rate is on the lower end of the range of rates collected by Wiser and Bolinger (2011), so this assumption is slightly optimistic for windpower, but consistent with the benchmark value of 5.8% used in a 2008 NREL study of the effect of financing variables on wind costs (Cory and Schwabe, 2009). A study of financing costs for Euro-area onshore wind (World Economic Forum, with data collected by Bloomberg New Energy Finance) suggests 2011 interest rates of ~6% (Gurung and von Bismarck, 2011), only a few tenths of a percent above the 2008 U.S. rate. From the compilation of Wiser and Bolinger (2011), 20 year loans are currently being offered for windpower projects, though most loans are shorter, making a 20 year duration a slightly optimistic assumption. The optimistic assumptions on loan duration and rates make our windpower costs some 10% lower than if mean values in Cory and Schwabe (2009) were used.

Operations and maintenance costs as reported by new wind facilities are again collected by Wiser and Bolinger (2011), who estimate a mean of ~\$10/MWh. (Wind generation is characterized by both fixed and marginal O&M costs, but the costs in Wiser and Bolinger (2011) have been converted to the unit \$/MWh, giving the appearance of being marginal only.) Integration costs,

which include provision of backup capacity to buffer intermittent renewable generators, are estimated by the AWS Truewind survey at ~\$5 per MWh (Corbus et al., 2010) by simulation of incorporating windpower into the electricity grid of the Eastern United States. Note that some fraction of integration costs might not be borne by generators themselves, resulting in an additional implicit subsidy and reducing the renewables premium slightly, but the amount is so small relative to total wind costs that it does not significantly affect the overall analysis. We do not include the costs of building additional transmission (which are expected to be small, \$3.5/MWh, < 5% of generation costs EIA, 2011b), on the assumption that these too would not be borne by individual renewables generators and so not relevant to RPS feasibility. (In fact, if transmission costs are reflected in wholesale rates, they benefit renewables by driving up their electricity revenue and reducing renewables premiums).

The resulting levelized cost of wind generation then becomes \$65/MWh at a 40% capacity factor and \$75/MWh at 33%. We neglect costs associated with taxation (i.e. we essentially assume the maximum possible accelerated depreciation).

$$\left(\frac{(\$2/W)(9\%/yr)}{(8760 \text{ h/yr})(0.40)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) + \left(\frac{\$10}{\text{MWh}} \right) + \left(\frac{\$5}{\text{MWh}} \right) \approx \$65/\text{MWh}$$

$$\left(\frac{(\$2/W)(9\%/yr)}{(8760 \text{ h/yr})(0.33)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) + \left(\frac{\$10}{\text{MWh}} \right) + \left(\frac{\$5}{\text{MWh}} \right) \approx \$75/\text{MWh}$$

These cost estimates are consistent with wind cost estimates from the IEA (2010) and the 2011 World Economic Forum reports (Gurung and von Bismarck, 2011) that range from \$60/MWh to \$110/MWh depending on cost, siting, and financing assumptions.

These generation costs are effectively reduced by the PTC, which provides a rebate based on initial construction costs. Using the same equation, we find that the PTC is valued at \$15 and \$20/MWh for 40% and 33% capacity factors, respectively, reducing the effective generation cost of wind for Iowa-type sites from \$60 to \$45/MWh and for Illinois-type sites from \$75 to \$55/MWh. Note that the PTC provides greater support relative to revenues for worse wind sites because the size of the rebate is based on peak installed capacity, not on actual electricity generated.

$$\left(\frac{(\$2/W)(9\%/yr)(30\%)}{(8760 \text{ h/yr})(0.40)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) \approx \$15/\text{MWh}$$

$$\left(\frac{(\$2/W)(9\%/yr)(30\%)}{(8760 \text{ h/yr})(0.33)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) \approx \$20/\text{MWh}$$

Market value of wind electricity. Because wind speeds in Illinois, Iowa, and Indiana peak during the night when electricity demand and prices are at a minimum, wind generators likely receive a lower average price than the mean wholesale price. We have however optimistically assumed that wind generation will receive the full wholesale price. We do use two different wholesale rates in this paper. For estimating a mean national wind premium in Table 1, we use an approximate 2010 national wholesale rate of \$40/MWh reported by Wisner and Bolinger (2011), but for the Illinois-specific analysis in the remainder of the paper we use Illinois rates which are slightly cheaper, at \$35/MWh in 2010 (ComEd, 2011). (This value is consistent with the Great Lakes mean wholesale rate reported in Wisner and Bolinger, 2011.) Regional Iowa prices are lower, but we optimistically assume that Iowa wind generators receive the Illinois wholesale price (Wisner and Bolinger, 2011).

Because wholesale electricity prices of \$35/MWh are significantly smaller than the wind generation costs calculated above, even given the contribution of the PTC, windpower requires additional price support. The resulting wind premium, the necessary additional level of support that would come from state RECs, is for Iowa wind \$30/MWh without the PTC and \$15/MWh with it (\$65–\$35=\$30, and subtracting the \$15 PTC subsidy leaves \$15). For wind from Illinois, the wind premium would be \$40/MWh without the PTC and \$20/MWh with it. In both cases, the PTC provides half the necessary support, and state RECS would have to provide the other half for windpower to be economically feasible. In wind-endowed Iowa, the cost of generating windpower is a bit less than twice the wholesale rate (the wind premium is slightly less than the wholesale rate). In less wind-endowed Illinois, windpower costs are more than 2 × wholesale, i.e. in the current cost landscape, Illinois wind generators would have to receive more in state and federal subsidies than they would in revenues from selling windpower.

C.1.2. Solar premium

Solar generation costs. The solar carveout accepts both solar thermal generation and photovoltaic (PV) generation, but given the price advantage of solar PV (EIA, 2011b), we do not expect solar thermal to contribute significantly to the Illinois RPS. The upfront cost of solar photovoltaic facilities is the dominant factor in levelized solar generation costs, even more so than for wind. Solar photovoltaics require an order of magnitude less O&M per unit electricity generated than do wind turbines. Their installation costs are higher, both because the solar module itself is more expensive per unit of electricity generated and because of significant other installation costs (labor and parts for initial grid integration).

We use here two separate sources for solar. First, we use total installed cost numbers for the third quarter of 2011 compiled by the Solar Energy Industries Association (SEIA, 2011) using data from PV installers, manufacturers, state agencies, and utilities. These are broadly consistent with inferred solar costs deduced from actual power purchase agreements (PPAs) signed in 2011 Q4 in California (California Public Utilities Commission, 2012). We then repeat the calculations using a lower-bound set by the cheapest 2011 solar projects (Barbose, 2012) and consistent inferred costs deduced from contracts signed by solar facilities currently under development that will begin contributing to the California RPS in 2013–2015 (The California Energy Commission, 2012). Note that the 2011 drop in solar costs means that values listed in the IEA 2010 report (IEA, 2010) are out of date.

The installed cost of solar PV exhibits significant economies of scale, with utility-scale projects costing about half as much as residential projects. The compiled install costs from SEIA are \$6.24/W_p for residential installations, \$4.94/W_p for commercial, and \$3.45/W_p for utility-scale projects (where W_p refers to “Watts peak”, the DC power output given illumination with a solar-like light source of intensity 1000 W/m²). The mean install cost of solar therefore depends on the size breakdown of projects. For this work we assume that all projects contributing to the Illinois RPS are utility-scale. This puts a lower bound on the premium but is also the more appropriate assumption for projections as large-scale solar generation ramps up in Illinois. (The size breakdown assumption is in fact less important to the mean solar premium than it may seem, because the different size classes also receive different electricity prices. The smaller and more expensive facilities are permitted net-metering, i.e. effectively receiving the higher retail rate, which partially compensates for their higher upfront costs.)

Note that while solar costs are reported in dollars per Watts peak (W_p) scaled to an insolation of 1000 W/m², no region on Earth receives an average insolation so high. For a Midwestern

state like Illinois, actual power produced over a typical year is only 15% of nominal capacity. In high-insolation areas like the U.S. Southwest, the effective capacity factor can reach 20%. (Values are based on the NREL PVWatts model, Marion et al., 2001.) Throughout this work we compute solar premiums for both the Midwestern region specified in the Illinois RPS and for these maximum U.S. insolation regions.

To calculate generation cost in \$/MWh, we assume again that new installations are financed by a 20 year, 6% loan leading to an amortization rate of 9% per year. We include operations and maintenance for completeness, though these are nearly negligible at only ~\$0.012 per watt of peak capacity per year. (O&M costs are reported by the EIA (2010) based on data collected by the Office of Integrated Data Analysis from industry and governments sources, including the DOE Fuel Offices and the National Laboratories.) The marginal O&M cost is reported as zero.

All cost calculations here assume a fixed-axis, utility scale project. Some utility-scale projects are now beginning to use single-axis tracking systems (e.g. First Solar's "AV Ranch One"). Tracking systems increase generated power but require increased installed and O&M costs. Because new projects at present have not converged on a single choice, and include both tracking and non-tracking options, we assume that the net cost differential is currently small and can be neglected. Tracking systems do represent a possible avenue for decreasing the levelized cost of solar generation, if their costs can be reduced in the future. In this case the cost analysis would have to take into account and adjusted capacity factor to represent the higher generation possible with tracking.

Using the SEIA utility-scale figure of \$3.45/W_p, the estimated cost of solar generation is \$245/MWh at a typical Midwest capacity factor of 15%. That is, the cost of generating electricity by solar photovoltaics in the Midwest is approximately seven times the current wholesale electricity price

$$\left(\frac{(\$3.45/W)(9\%/yr) + \$0.012/W_p/yr}{(8760 \text{ h/yr})(0.15)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) \approx \$245/\text{MWh}$$

For desert Southwest sites with capacity factor of 20%, the costs are 25% lower. (The ratio of capacity factors is 0.15/0.20=0.75.) Solar costs then drop to \$185/MWh.

To compare to PPA-derived estimates, or to calculate the solar premium, we need to take the federal PTC into account. As with wind, the federal PTC reimburses 30% of the installed cost for solar, offsetting \$70/MWh and \$55/MWh of the solar premium for the 15% and 20% capacity factors, respectively, assuming SEIA Q3 pricing. (Again, note that the PTC provides a greater relative subsidy for worse sites.)

$$\left(\frac{(\$3.45/W)(9\%/yr)(0.3)}{(8760 \text{ h/yr})(0.15)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) \approx \$70/\text{MWh}$$

and for higher-insolation areas, the PTC benefit is

$$\$70/\text{MWh} \cdot 0.75 \approx \$55/\text{MWh}. \quad (\text{C.1})$$

The SEIA-based solar generation cost inclusive of the PTC is then \$175/MWh in the Midwest, and \$130/MWh in the desert Southwest. These costs are consistent with 2011 California utility-scale solar PV PPAs (for projects coming online in 2011), which range from \$110/MWh to \$145/MWh (California Public Utilities Commission, 2012).

There are several indications that costs are in fact now lower or are expected to become so in the near future. A 2012 request for proposals for renewable energy projects from the Southern California Public Power Authority places a ceiling on solar bids of \$110/MWh. And California PPAs signed in 2011–2012 for solar projects expected to come online after 2012 are reported at approximately \$100/MWh (California Public Utilities

Commission, 2011). These values suggest an anticipated install costs within the upcoming few years approximately 30% lower than the SEIA Q3 2011 costs, or approximately \$2.50/W_p. Costs of \$2.50/W_p are also consistent with unpublished reports of the most cost-effective 2011 solar projects (Barbose, 2012). In the analysis here, we include this lower estimate as a lower bound on the uncertainty in current solar costs.

With costs at \$2.50/W_p, the pre-PTC levelized cost becomes \$180/MWh in the Midwest

$$\left(\frac{(\$2.50/W)(9\%/yr) + \$0.012/W_p/yr}{(8760 \text{ h/yr})(0.15)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) \approx \$180/\text{MWh}$$

and \$135/MWh in the high-insolation Southwest (lower by 25%). The value of the PTC itself decreases to \$50 in the Midwest and \$40 in the Southwest, so that post-PTC costs become \$130/MWh in the Midwest and \$95/MWh in the Southwest.

$$\left(\frac{(\$2.50/W)(9\%/yr)(0.3)}{(8760 \text{ h/yr})(0.15)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) \approx \$50/\text{MWh}$$

$$\left(\frac{(\$2.50/W)(9\%/yr)(0.3)}{(8760 \text{ h/yr})(0.20)} \right) \left(10^6 \frac{\text{Wh}}{\text{MWh}} \right) \approx \$40/\text{MWh} \quad (\text{C.2})$$

Market value of solar electricity. Unlike windpower, the value of solar-produced electricity likely exceeds the mean wholesale price, because solar production peaks in the middle of the day at times when electricity demand is generally largest and so prices highest. In Illinois, the average peak time wholesale price in 2010 was \$45 per MWh (ComEd, 2011) for the largest utility in the State (Commonwealth Edison) and we adopt this as the market value for solar electricity from utility-scale facilities. Because we consider here only utility-scale facilities, we disregard the smaller PV installations (< 40 kW capacity) that in Illinois are permitted net metering and so receive the full retail rate of \$100/MWh. The higher cost of the smaller installations means their net premiums are higher and so they are less cost-competitive.

Renewables premium for solar electricity. Combining received prices ($P_i = \$45/\text{MWh}$) with the average post-PTC Midwest solar generation cost of $C_i = \$175/\text{MWh}$ with it yields an average solar premium for a typical Midwest \$130/MWh. This \$130/MWh price is the SREC price needed to stimulate solar investment under the Illinois RPS. That is, Midwest solar requires more than eight times the subsidy per unit electricity as does wind at SEIA Q3 installed costs. If installed costs are as low as \$2.50/W_p, then the REC price for Midwest sites would be \$85/MWh.

For comparison, net metered residential projects in the Midwest have a premium (after the PTC) of \$230/MWh and commercial projects a premium of \$200/MWh (using 2011 Q3 prices), meaning residential solar is uncompetitive relative to utility-scale despite the net metering benefits.

C.2. Cost caps

In this section we discuss the derivation of cost-cap-limited REC prices in \$/MWh. We first show detailed calculations for the state of Illinois, first discussing the volume of new capacity required under the IL statute for five states (IL, CO, OH, WA, and NJ) that are shown in Table 1. Because the cost caps of different states are specified in very different terms, they cannot be compared without converting them to equivalent units. All calculations here are done in current U.S. dollars, using RPS data from the Union of Concerned Scientists Renewable Electricity Standards Toolkit (UCS, 2008). We begin with a discussion of cost caps that apply to the mean REC rate and then discuss solar-specific caps.

C.2.1. General RPS cost caps

Illinois. The Illinois cost cap is stated in somewhat complicated terms and has a complicated phase-in. The total allowable dollar amount of the RPS program is always set by pegging it to a percentage of the retail sales of a base year, but both the percentage and base year change over time (though usefully for analysis, by 2011 all base years lie in the past, removing any uncertainty in total cap amount). In 2008, the RPS could not cost more than 0.5% of the total retail sales in 2007. In 2009, the cap is the greater of an additional 0.5% of the 2008 retail sales or 1% of the 2007 retail sales. In 2010, the cap is again the greater of an additional 0.5% of the 2009 sales or 1.5% of the 2007 sales. In 2011, the cap is the greater of an additional 0.5% of the 2010 sales or 2% of the 2007 sales. After 2011, the cap is fixed at the greater of 2.015% of the 2007 sales or the incremental amount from 2011. For the sake of simplicity, and since it makes little difference, we simply assume that the cap is 0.5% of the retail sales in 2008, 1% in 2009, 1.5% in 2010, and 2% in 2011 and thereafter. Each year's retail sales is calculated by adopting the 2010 sales and a 1% annual growth rate. In this way, the mean cost cap for Illinois in a given year, y , can be expressed as

$$\frac{(\text{cap percentage})(\text{retail price})}{(\text{RPS requirement})(1.01)^{y-2011}} \quad (\text{C.3})$$

For example, in 2025, when the RPS requirement is 25% of retail sales and the cost cap is $\sim 2\%$ of the 2011 retail sales, the cap can be translated into dollars per MWh as

$$\frac{(2\%)(\$100/\text{MWh})}{(25\%)(1.01)^{2025-2011}} \approx \$7/\text{MWh}.$$

If the mean REC rate exceeds the cost cap value approximated in Eq. (C.3), then the RPS will go into failure mode and the tendered RECs will be less than the number required by the legislation. Failure mode need not mean that all RECs must trade at the average capped value, though, since solar and wind RECs trade in separate markets. A cost cap of an average \$7/MWh in 2025 could be met if, for example, even if solar RECs trade at \$100/MWh, if all the rest of the RECs trade at \$1/MWh (since $6\% \times \$100/\text{MWh} + 94\% \times \$1/\text{MWh} \approx \$7/\text{MWh} \leq$ the 2025 cost cap).

Colorado. The Colorado RPS, which was adopted in 2004 by ballot initiative and expanded in 2007 by House Bill 1281, will implement a 20% renewables requirement for investor-owned utilities in 2020. The cost of RPS compliance is limited to 2% of retail sales and the retail rate in Colorado, at \$83/MWh, is somewhat lower than that of Illinois. The cost cap will therefore be $\approx (2\%)(\$83/\text{MWh})/20\% = \$8.3/\text{MWh}$ assuming that electricity prices do not increase out-of-pace with inflation. The Colorado cap is slightly higher than that of Illinois because the smaller requirement and continued pegging of the cost cap to current retail sales outweigh the effect of the state's lower electricity prices.

Ohio. The Ohio legislature enacted an RPS as part of Senate Bill 221 in 2008. The bill will require that 12% of the state's electricity come from non-solar renewables (there is a separate solar carveout) in 2025. However, utilities are not required to comply with the full requirement if the expected cost of compliance exceeds 3% of the cost of producing the state's electricity in absence of the RPS. At the regional wholesale rate of \$35 per MWh (Wiser and Bolinger, 2011), this cost cap limits the 2025 non-solar REC rate to $(3\%)(\$35/\text{MWh})/12\% \approx \$8.75/\text{MWh}$ on average.

Washington. Washington State enacted an RPS by ballot initiative that constitutes a 15% renewables requirement in 2020. The Washington RPS comes with a cost cap that allows utilities to fall out of compliance if the renewable energy increases their costs by more than 4%. Their cost cap is therefore $(4\%)(\$66/\text{MWh})/15\% \approx \$18/\text{MWh}$.

C.2.2. Solar cost caps

New Jersey. The New Jersey RPS contains a significant solar carveout calling for 5316 GWh of solar generated electricity in 2026. The cost of the solar program is effectively capped by a non-compliance penalty which is scheduled to decrease from \$711/MWh in 2009 to \$594/MWh in 2016 when the solar requirement is 1150 GWh. Prior to the passage of the Solar Advancement Act in 2010, the solar carveout was also limited to 2% of the state's retail sales, but this limit has now been removed.

Ohio. The Ohio RPS also includes a solar carveout that reaches 0.5 of the electricity sales in 2025. The carveout is subject to the general RPS cap, but is effectively limited by a noncompliance penalty which is currently set at \$400/MWh, but decreases by \$50 every other year until reaching a minimum of \$50/MWh in 2024. Note that this limit is over ten times lower than the New Jersey limit and substantially less than the solar premium calculated above.

Appendix D. Treatment of utility vs. ARES customers

When the Illinois RPS was first enacted in 2007 as part of Public Act 095–0481 (the “Illinois Power Agency Act”), the RPS was applicable only to customers of investor-owned Electrical Utilities (EU's). A 2009 amendment (Public Act 96–0159) extended RPS requirements to Alternative Retail Electricity Suppliers (ARES) as well, though somewhat differently in application. In some cases, compliance by ARESs may (or must) be achieved with Alternative Compliance Payments rather than REC sales. However, revenue from these payments are used to purchase RECs and the payment amount each year is set by the previous year's REC prices, effectively meaning that compliance is demonstrated entirely through REC purchases.

Although the total renewables requirement is the same for ARES and EU customers, their technology-specific carveouts differ slightly. Those differences are of no practical significance for RPS implementation, however. EU's are required to supply 75% of their renewable portfolio from wind and ARESs only 60%. The effective statewide wind carveout averaged over all customers is then necessarily bounded between 60% and 75% of the RPS. At present, because ARESs and EUs each supply approximately half of the state's electricity, the current effective wind carveout falls in the middle of this range at $\sim 70\%$ $((0.5)(75\%) + (0.5)(60\%) \approx 70\%)$. This is the number we use in the analysis here. The effective wind carveout may decrease over time, since the ARES market share in Illinois appears to be increasing. Provided wind remains the cheapest renewable, however, that change is of no import since nearly the entire non-solar portfolio is likely to be met with windpower regardless.

While EUs and ARES are given the same final solar carveout, they are treated differently during its phase-in. In 2010, House Bill 6202 added a ramp-up period for EU solar portfolios requiring that they increase steadily from 2013 to 2016 (beginning as 0.5% of the portfolio and rising to 6%), after which the solar carveout remains constant. ARESs have no ramp-up, and their solar carveout instead simply begins in 2016 at 6%. Because solar costs are so high, this difference in phase-in does matter to our projections of the cost of fulfilling the Illinois RPS, though only for the narrow time window of 2013–2016. The projections in this work assume a continued 50:50 division between EU and ARES customers. Were the ARES fraction to increase, the more abrupt state-average introduction of the solar requirement would produce a steeper rise in REC prices needed for RPS fulfillment over this time window.

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