Reducing Variable Generation Curtailment through Flexible Transmission Expansion and Operation in the United States

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1. Introduction

Over the past two decades, variable resource renewable generation (VG) capacity, made up of largely wind and solar technologies, has grown rapidly in the United States. From 2001 to 2016, the share of generation from wind and solar technologies grew from a mere 1.8% to almost 7% of total U.S. electricity generation, and this trend in growth is expected to continue (Cole et al. 2016; EIA 2017). As the penetration of VG technologies increases, the potential for curtailment, or the intentional reduction in generation from VG capacity when generation exceeds load, can substantially increase (Denholm and Margolis 2016; Denholm, Clark, and O'Connell 2016).

Curtailment of VG is implemented as a measure to address an imbalance in demand and supply of energy during times of localized or system-wide surplus generation, i.e., when supply exceeds demand for electricity. Such surplus generation may result from insufficient transmission capacity to export surplus power (to neighboring regions), inability to store surplus energy, and/or inability to ramp down generation from committed thermal units (Bird, Cochran, and Wang 2014; Fink et al. 2009). Over the past few years, curtailment levels in the U.S. have typically ranged from 1% to 4%. However, curtailment in specific regions and certain conditions have been substantially higher. For instance, prior to a substantial expansion of the transmission system, the Electric Reliability Council of Texas (ERCOT) reported curtailment levels approaching 17% in 2009 (Bird, Cochran, and Wang 2014). Curtailment is a concern to owners of VG, as well as to system operators, because it jointly diminishes the value of the resources (to the grid) and the potential returns from selling power (to owners). When generation from a wind or solar plant is curtailed, energy (and specifically, zero-marginal cost energy) is wasted. This lost energy decreases the value of the plants and can drive suboptimal deployment of resources from the perspective of a societal system planner. Therefore, mitigating curtailments of VG is a key factor in improving the economic value of renewable projects, especially as electricity demand is increasingly served by VG.

A key driver of curtailment can be constraints on available transmission (Bird, Cochran, and Wang 2014; Fink et al. 2009). With sufficient transmission capacity, even if local VG far exceeds local load, the excess generation can be exported to serve load in a neighboring region. However, if transmission capacity is constrained and local load is unable to absorb all the VG, the excess VG must be curtailed. Previous studies have shown that curtailment can be reduced considerably by expanding the transmission system (Jorgensen, Mai, and Brinkman 2017).

In addition to constraints in transmission availability, non-optimal coordination of transmission operation can also lead to curtailment – despite there exist potential opportunities to export surplus generation and reduce curtailments, these opportunities are not always realized due to a lack of transmission coordination. Such inefficiencies can be caused by institutional and operation barriers or technical transmission infeasibilities. This inter-regional "friction" is often represented in electricity-sector models as a "hurdle rate," in units of $/MWh, that is applied to flows between regions. For example, National Renewable Energy Laboratory's (NREL's) Resource Planning Model (RPM) included hurdle rates from the Western Electricity Coordinating Council (WECC) for electricity transmission between balancing areas (BAs) (Mai et al. 2015); Jordan and Piwko (2013) assumed a $5/MWh hurdle rate between neighboring companies in WECC. The Eastern Renewable Generation Integration Study (Bloom et al. 2016) applied a $10/MWh hurdle rate across eastern regional transmission organizations (RTOs) to reflect various elements of market friction. In the Western Wind and Solar Integration Study (Lew et al. 2013), the authors did not include any hurdle rates in the analysis, but acknowledged the need to incorporate hurdle rates into future work to better represent actual operational coordination and challenges.

In this study, we examine the relationship between VG deployment, VG curtailment, and transmission expansion. Specifically, we use the Regional Energy Deployment System (ReEDS) capacity expansion model to evaluate how different levels of VG deployment, transmission expansion, and inter-regional cooperation (represented through hurdle rates) impact VG curtailment and the overall capacity and generation mix. In addition, we quantify the electricity system costs of the various configurations of transmission expansion explored across scenarios.

Section 2 describes the ReEDS model, including its transmission representation, and also explains the scenario design. Section 3 presents the detailed results of transmission, curtailments, capacity and generation mix, as well as total system costs. Section 4 summarizes the conclusions and provides future research directions.

2. Methods

ReEDS Overview

In this study we implement the National Renewable Energy Laboratory's (NREL's) ReEDS model, a linear optimization model that determines the optimal investment in and operation of the generation and transmission system in the United States from present to 2050 (Eurek et al. 2016). ReEDS models 134 BAs for the contiguous United States and has another layer of spatial resolution with 18 model RTOs. ReEDS dispatches all generation using 17 annual time slices to capture seasonal and diurnal demand and renewable generation profiles. Additional model details are provided in the ReEDS documentation (Eurek et al. 2016).

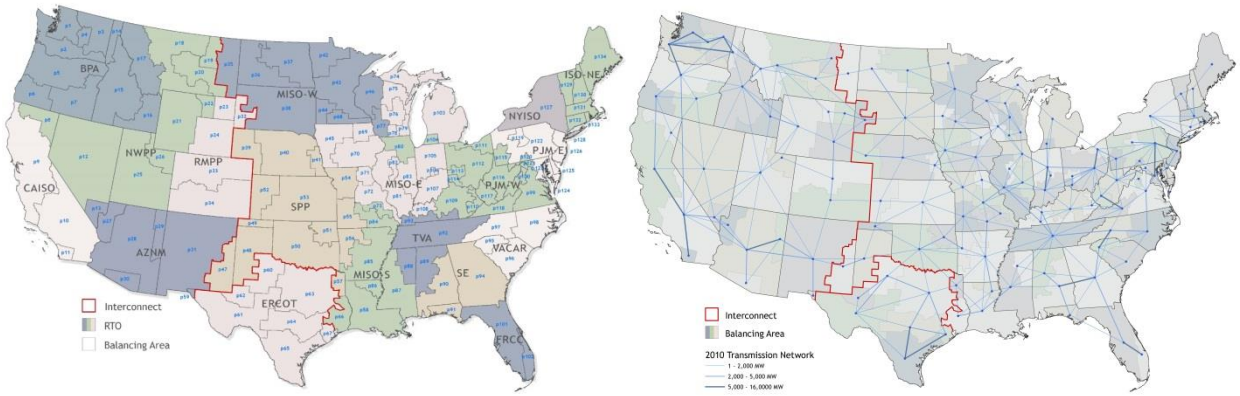


Figure 1. Map of ReEDS' 134 balancing areas (BAs) and 18 RTOs (left), and inter-BA transmission (right).

The model applies a linearized AC power flow approximation based on the fast decoupled load flow method, otherwise known as approximate DC power flow, for transmission representation (Eurek et al. 2016), and considers the co-optimization of both renewable energy capacity and transmission expansion based on system cost-effectiveness. The constraints for linear DC power-flow representation in ReEDS are shown below. Equation 1 represents the nodal power balance from Kirchhoff's current law, and Equation 2 shows the flow-limit constraints between inter-regional transmission flows based on line capacity. Equation 3 considers the transmission flow to be a linear function of the line susceptance multiplied by the angle differences between the sending and receiving nodes. The linear representation allows ReEDS to both improve the model fidelity of transmission lines and avoid non-linearity for the electricity system optimization.

$$Generation_j - Load_j = \sum_i Flow_{i,j} \quad (1)$$

$$Flow_{i,j} \leq Line\ Capacity_{i,j} \quad (2)$$

$$Flow_{i,j} = \left(Angle_i - Angle_j\right) \times Susceptance_{i,j} \quad (3)$$

For curtailment, ReEDS uses a statistical calculation to estimate expected surplus generation based on the expected electricity demand, VG output, minimum generation level for committed thermal units, and amount of electrical storage[1] between each solve year.[2] Changes in thermal fleet minimum generation level and new storage capacity can change curtailment patterns from one year to another (Eurek et al. 2016).

<u>Scenario Design</u>

Using ReEDS, we simulate and analyze a suite of future power system expansion scenarios to investigate the role of transmission in reducing VG curtailments. The Reference scenario assumes a business-as-usual power system evolution considering default physical, technological, and policy constraints. The High

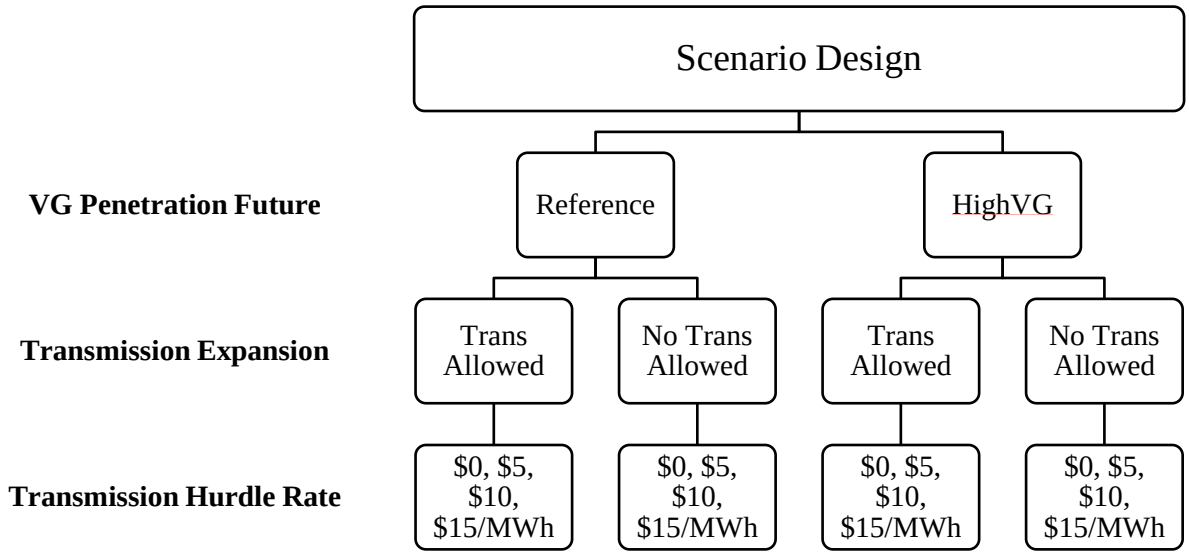
[1] ReEDS storage technologies include pumped-hydro storage (PHS), 8-hour batteries, and compressed air energy storage (CAES).

[2] ReEDS applies a 2-year time-step, therefore has 21 solve years from 2010 to 2050 in total.

Variable Generation (HiVG) base scenario prescribes the level of national VG to be 10% of total generation in 2020, 25% in 2030, 40% in 2040, and 55% in 2050. VG technologies are defined as utility-scale photovoltaics (PV), distributed PV, concentrating solar power without storage, and land-based and offshore wind. All scenarios use the 2017 Annual Technology Baseline for generator cost and performance inputs (NREL 2017), and the Annual Energy Outlook (AEO) 2017 Reference scenario for demand growth and fuel prices (EIA 2017). State and federal policies are represented as of June 1, 2017, including state renewable portfolio standards, California's AB 398 rule, the Regional Greenhouse Gas Initiative (RGGI), and federal tax incentives (Eurek et al. 2016).

To demonstrate the effects of both physical transmission constraints as well as operational challenges (limited interregional coordination), we first consider two transmission expansion futures: one that allows transmission capacity construction and one that prohibits any new transmission expansion.[3] Then, for each of these two transmission configurations, we implement four levels of hurdle rates ($0, $5, $10, and $15/MWh) for transferring power across the ReEDS RTO regions (see Figure 1 for a map of the ReEDS RTOs). The 16 resulting scenarios are shown in Figure 2. Within our modeling framework, hurdle rates represent the bilateral trading transaction costs, wheeling charges, and other transmission-related limitations between BAs (California ISO et al. 2016). The different levels of hurdle rates represent different levels of "market friction" between regions.

Figure 2. Scenario design showing the 16 scenarios used in this analysis



[3] For the case with "no transmission expansion," transmission lines that are currently under construction or have been approved are allowed to build, and there are no new transmission builds after 2020.

3. Results

Figure 3 shows the capacity and generation mix for the Reference and HiVG scenarios with no hurdle rates. These scenarios serve as a reference point for other scenario results that will be presented later in this section. The Reference scenarios see growth in VG and natural gas with declines in coal and nuclear.[4] The HiVG scenarios have much less conventional capacity by 2050 due to the prescribed VG requirement. Cumulative capacity is expected to double by 2050 under the HiVG scenario, mainly due to the relatively lower capacity factors of wind and solar PV technologies compared to conventional technologies. Per the scenario definition, more than half of the load is served by VG in the HiVG scenario by 2050.

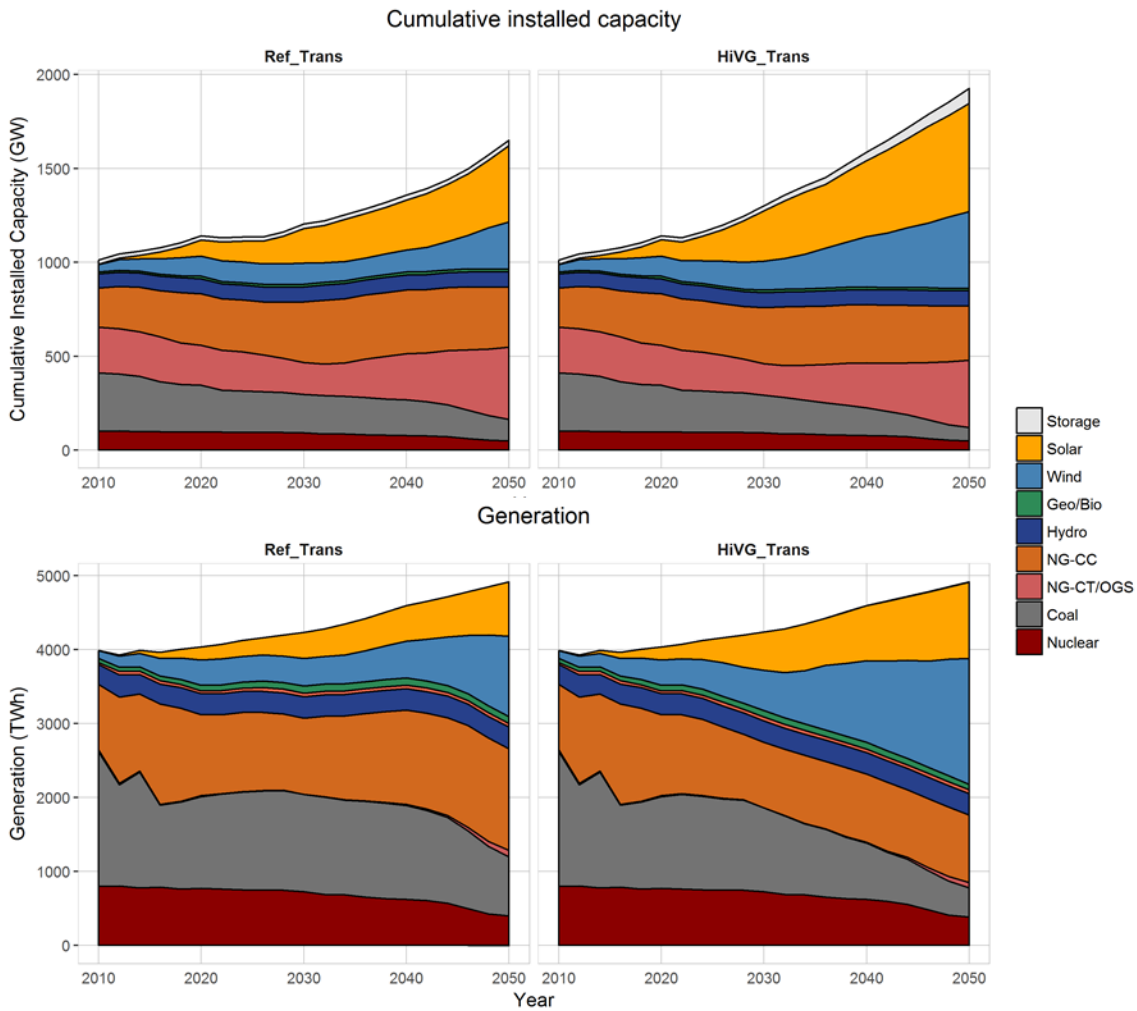


Figure 3. Cumulative capacity (top) and generation (bottom) by year for Reference and HiVG scenarios with no hurdle rates, allowing transmission expansion.

For the scenarios where transmission capacity expansion is allowed, higher levels of VG penetration drive additional transmission expansion (Figure 4). The cumulative transmission capacity is always higher

[4] ReEDS applies an age-based retirement method for all generator type. Nuclear plants have a mix of 60-year and 80-year lifetimes. In addition to the age-based retirements, ReEDS also has additional utilization-based retirements for coal plants.

under the HiVG scenario than the corresponding Reference scenario. The impact of the hurdle rates on transmission investment can also be seen in Figure 4. Higher hurdle rates increase the cost of interregional power transfers and, therefore, result in less transmission investment – it is more cost-effective to build capacity locally than to ship or transfer power from plants built in regions with the best resources. Lower hurdle rates indicate fewer operational transmission barriers and lower costs to transfer power, allowing the system to more cost-effectively expand transmission capacity to regions with optimal resources. Under the Reference scenario, transmission capacity in 2050 declines from 104,000 GW-mi, with no hurdle rate, to 93,000 GW-mi, with a $15/MWh hurdle rate (11% reduction). Similarly, the transmission capacity decreases from 107,000 GW-mi to 96,000 GW-mi under HiVG scenario (10% reduction).

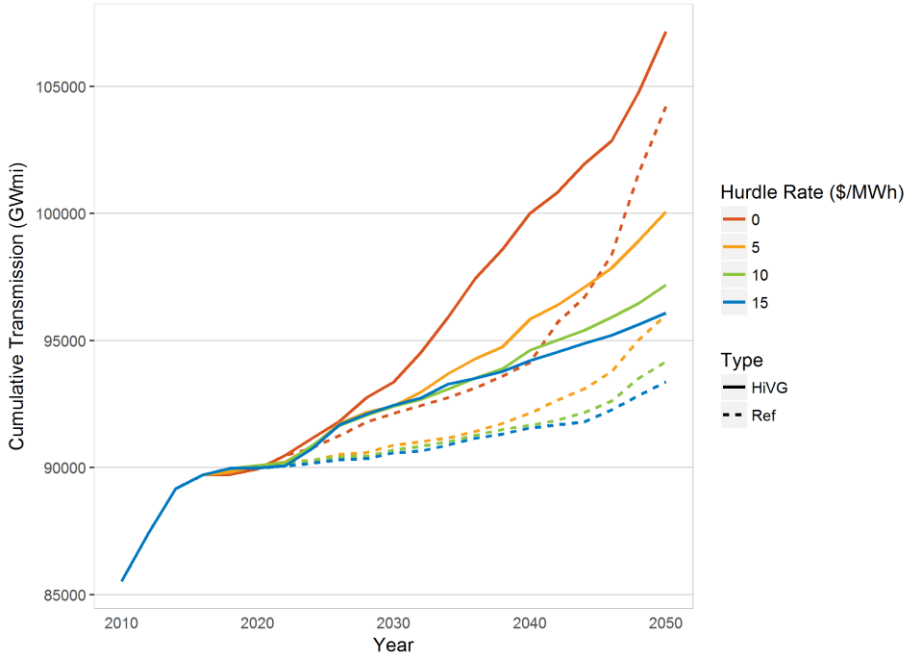


Figure 4. Total transmission capacity by year for transmission-allowed cases.

Transmission utilization follows a similar pattern as the transmission expansion: higher hurdle rates lead to lower utilization (Figure 5). The transmission utilization rate is defined as the national total transmission flow divided by total available transmission capacity. For example, in the HiVG scenario where new transmission is allowed, the utilization rate decreases from 33.3% to 20.0% with increasing hurdle rates. On the other hand, we find that in allowing transmission expansion, the transmission utilization rate increases. In Figure 4, the utilization rates in the scenarios that allow transmission are higher than in the corresponding scenarios that do not allow transmission.

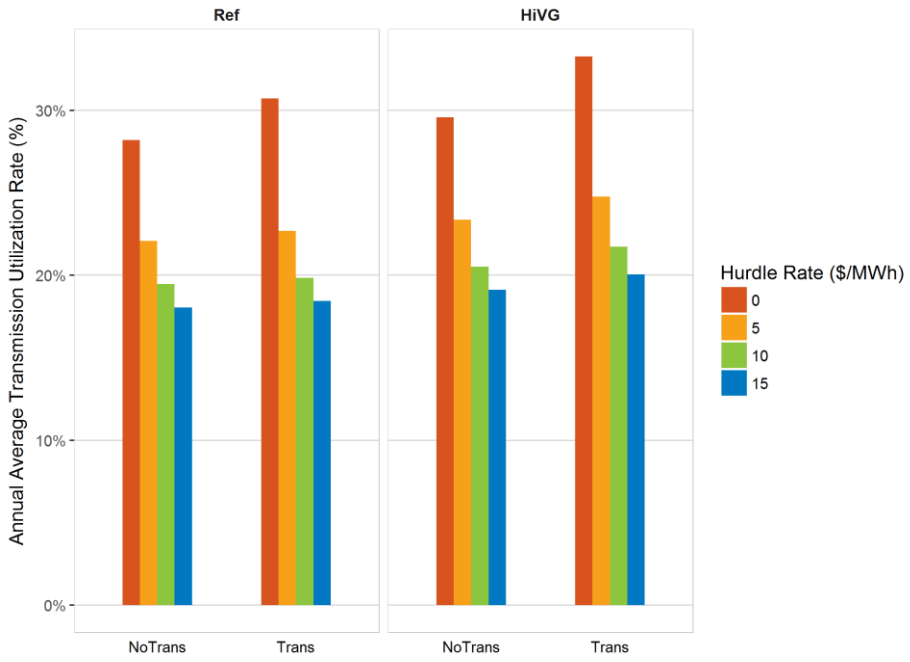


Figure 5. Annual transmission utilization rate (average across 2010 to 2050).

In these scenarios, the curtailment rate generally increases as VG penetration increases (see Figure 6). As a result, VG curtailments are higher under the HiVG scenario conditions (54–63 TWh by 2050) than under the Reference scenario conditions (18–27 TWh by 2050). As more VG is added to the grid, there are more hours where VG exceeds load and transmission export capabilities, resulting in an increased amount of curtailment.

Although the average curtailment levels[5] are relatively low at the national level (about 2% by 2050 in the HiVG scenarios), specific regions have higher curtailment levels. In the HiVG scenarios, state-level curtailment levels range from 0–9.3%, and in the Reference scenarios, they range from 0–6.2%.

Somewhat surprisingly, the results suggest that curtailment levels are quite similar under different transmission expansions and hurdle rates for the given VG penetration (Figure 6). For instance, the national average curtailment level for the HiVG scenarios only ranges from 2.1% to 2.5% in 2050 when the VG penetration reaches 55% of overall generation. Such similarities in curtailments under various transmission assumptions indicate the flexibility of the power system to use other options when building out the system. Despite the imposition of transmission constraints (e.g., no new transmission capacity expansion or higher transmission hurdle rates), ReEDS chooses to invest in more local generation and change the generation mix to improve flexibility. The result is that the model can integrate similar levels of VG without significantly increasing curtailment.

[5] Curtailment level is defined as total curtailment divided by overall VG generation (pre-curtailment).

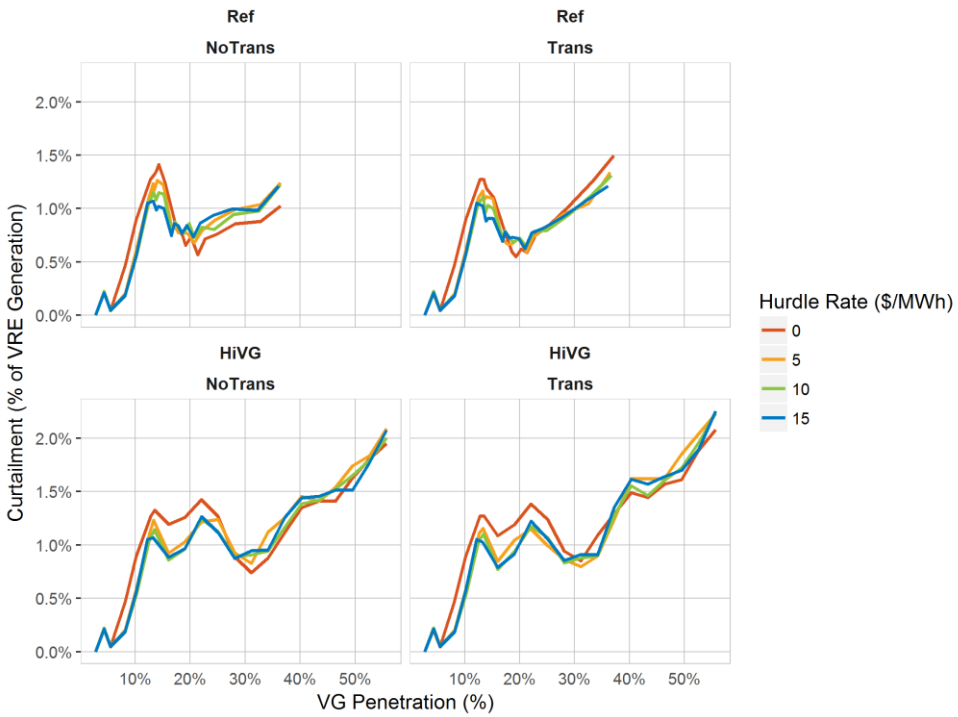


Figure 6. National curtailment level vs. VG penetration[6] for difference scenarios.

In addition to the system-wide or average curtailment levels, marginal curtailment rate is another metric for assessing the value of VG resources. Marginal curtailment rate is defined as the curtailment from an additional unit of wind or solar capacity into the grid. Figure 7 shows that the median marginal curtailment rates for both PV and wind grow with increasing VG penetration, with an especially high rate of increase in the marginal curtailment rate at penetrations exceeding 35% VG. The higher marginal curtailment rates indicate that a growing portion of new wind and solar capacities will be curtailed as the system reaches higher levels of VG.

[6] VG penetration is defined as post-curtailment penetration level.

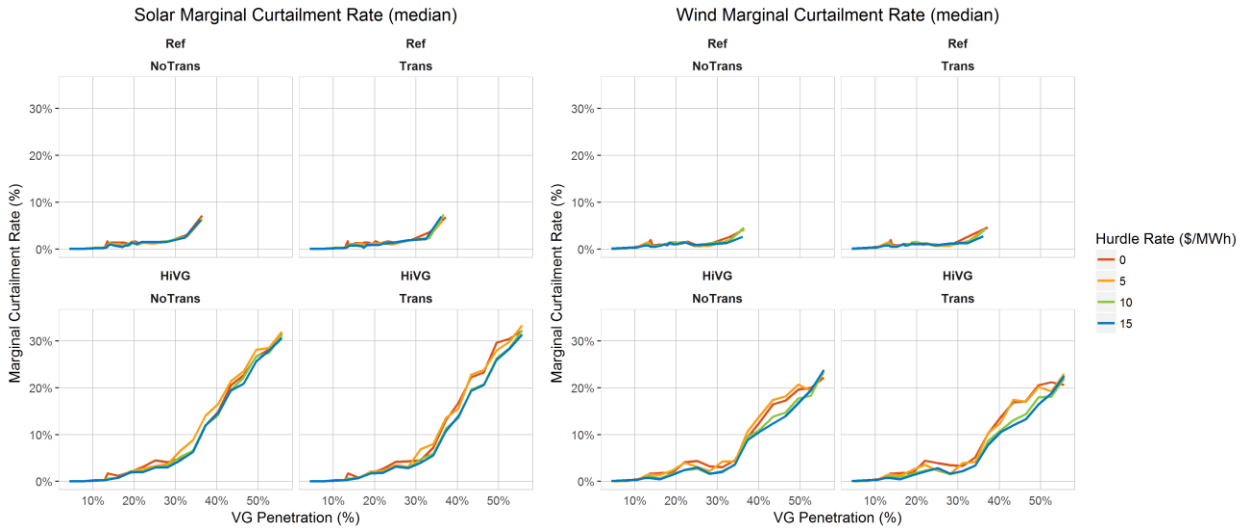


Figure 7. National median of marginal curtailment level for solar (left) and wind (right) by VG penetration

Despite the increase in marginal curtailment rates, the overall curtailment levels remain quite similar with different levels of transmission constraints. One of the reasons for limited impact on overall curtailment is that the ReEDS model changes its capacity and generation mix as transmission is increasingly constrained. Figure 8 shows that with increasing hurdle rates, natural gas combined cycle (NG-CC) capacity and solar capacity are increasingly relied upon, but wind and natural gas combined turbine (NG-CT) capacity are reduced. In addition, higher hurdle rates bring in more storage capacity under HiVG scenario. The generation mix exhibits similar changes, but also has lower generation from coal plants for all scenarios. In other words, as transmission gets more constrained, natural gas and PV are displacing coal and wind generation. The reduction in coal generation lowers the minimum generation level of the coal plants (i.e., more plants are turned off for longer periods), which in turn increases the flexibility of the system and allows the additional PV to be integrated without increases to the overall curtailment rate.

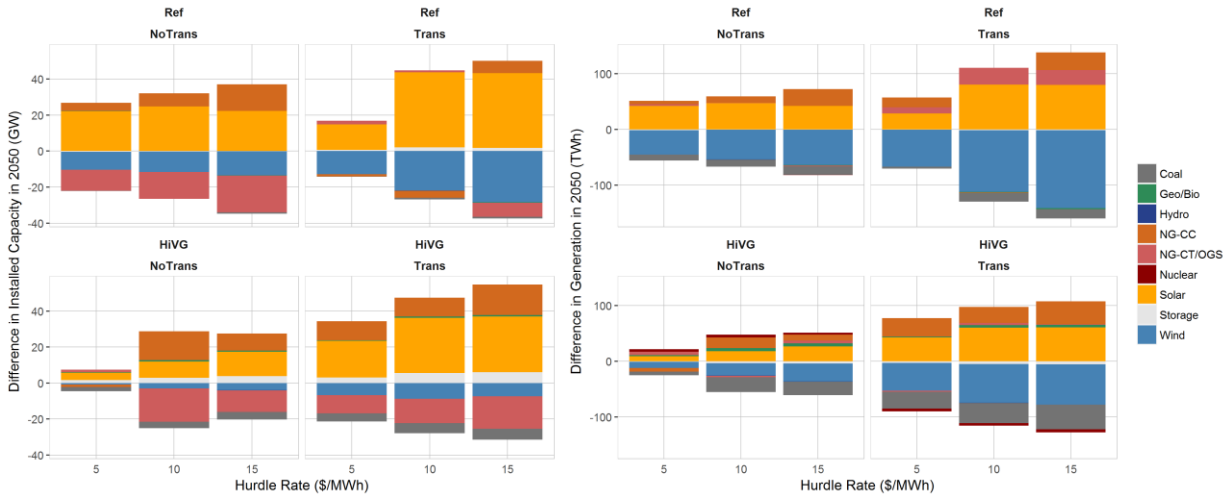


Figure 8. Capacity (left) and generation (right) difference from no hurdle rate case in 2050

Generally, wind plants are built in the highest quality wind resource locations, which are often relatively far from load centers.[7] Coal plants are often large centralized projects that meet local load, however, given their large capacity, the full capacity often exceeds the local load requirement, allowing them to export additional generation to neighboring, high-load regions.[8] Thus, both plant types depend heavily on transmission to serve load. In contrast, solar PV and natural gas plants are often smaller and located close to the load centers, and therefore depend less on transmission availabilities. As transmission becomes more constrained, coal generation and wind generation are generally replaced by more localized solar PV capacity. NG-CC plants are built to fill in for load that was served by coal plants and to fill the PV generation gap at night. Figure 9 demonstrates the shift in wind and PV capacity from more remote regions to those that are close to load centers. Higher hurdle rates result in less wind capacity in the Midwest and Northwest, primarily in Iowa, Montana, and Wyoming, but more solar capacity in California, Texas, and the Southeast to serve load in those areas.

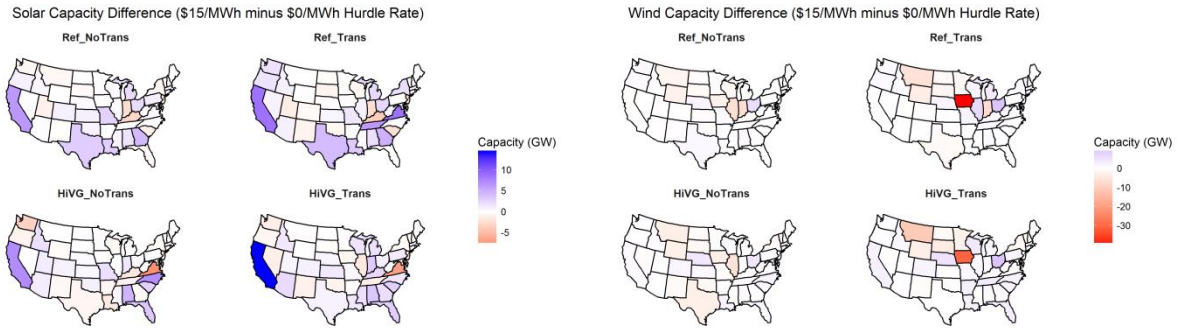


Figure 9. Installed capacity difference in 2050 from $15/MWh hurdle-rate scenario to $0/MWh hurdle-rate scenario for solar (left) and wind (right).

The changes in capacity and generation mix, together with the remote-to-local generation changes, allow the system to maintain nearly the same curtailment levels even as we layer on transmission restrictions. However, such solutions are more costly to achieve. For example, Figure 10 shows the marginal cost of curtailment for each of the scenarios, where the marginal curtailment cost is defined as the increase in total system cost per unit of additional curtailment. Although curtailment is similar across the scenarios, the marginal cost of curtailment increases with more constrained transmission systems. Under HiVG scenarios, the marginal curtailment price increases by 3% from the $0/MWh hurdle rate scenario to the $15/MWh hurdle rate scenario when transmission expansion is not allowed. This means that additional curtailments are more expensive with restrictive transmission systems, even if the system can maintain a similar level of curtailments by shifting the generation mix.

[7] According to AWEA's 2016 Fourth Quarter Market Report (American Wind Energy Association, Feb. 2017), the five states with most wind installed capacity are Texas, Louisiana, Oklahoma, California, and Kansas, representing half of the total U.S. wind capacity.

[8] States with the most coal capacity include Ohio, Texas, Indiana, Pennsylvania, and Illinois, accounting for 31% of the total U.S. coal power-plant capacity (EIA, https://www.eia.gov/electricity/data.php#gencapacity).

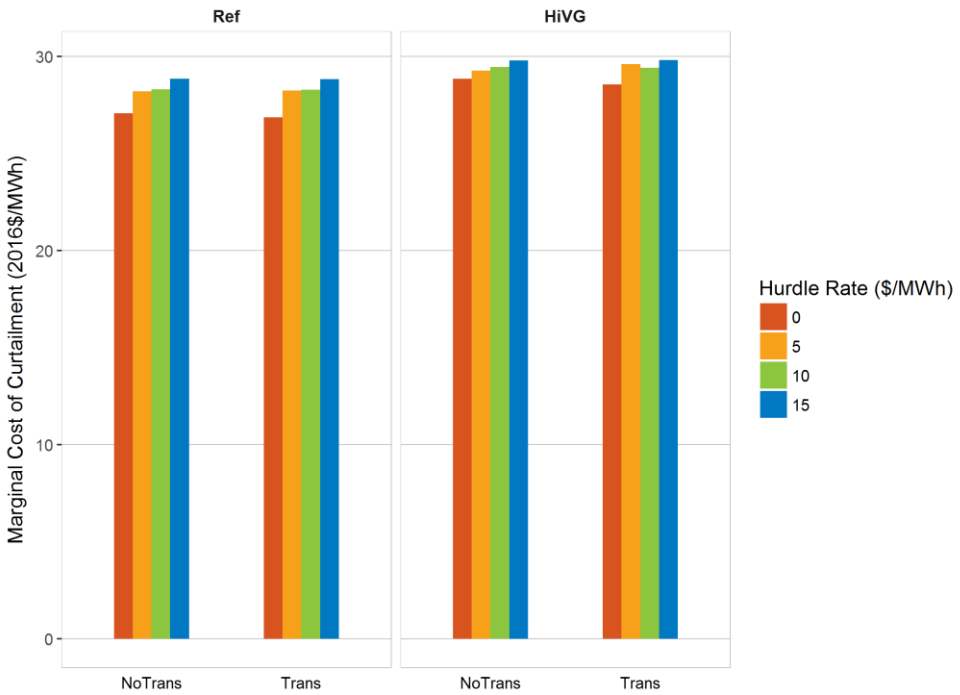


Figure 10. Annual marginal cost of curtailment (median cost across regions for each year, averaged across 2010 to 2050) for different scenarios.

Total system cost is another metric we use to evaluate the economic performance of the whole power system. The total system cost is calculated as the present value of total capital, operation and maintenance, fuel cost, transmission, and other investments for the entire electricity system from 2016 to 2050 at 3% discount rate. Figure 11 shows that total system cost increases as the hurdle rate grows, even though the curtailment levels for the different scenarios are similar. For example, under the HiVG scenarios when transmission is allowed, the total system costs are $20, $28, and $34 billion (2016$) higher with $5/MWh, $10/MWh, and $15/MWh hurdle rates, respectively, than the no hurdle-rate scenario (Figure 11). For perspective, the Reference scenario that allows transmission and has no hurdle rates has a total system cost of $3,476 billion (2016$). When hurdle rates are applied, ReEDS relies more on local generators to serve the load – despite the fact that these local resources have ultimately higher generating costs than imported electricity, the cost of the hurdle rates in addition to the cost of imported electricity make the local generation the least-cost resource. Although such measures help maintain relatively lower curtailment rates (i.e. comparable to a more relaxed transmission system), it does result in an increase in the overall system cost. These higher costs also suggest the potential of regional collaborations in transmission operation to reduce overall economic losses.

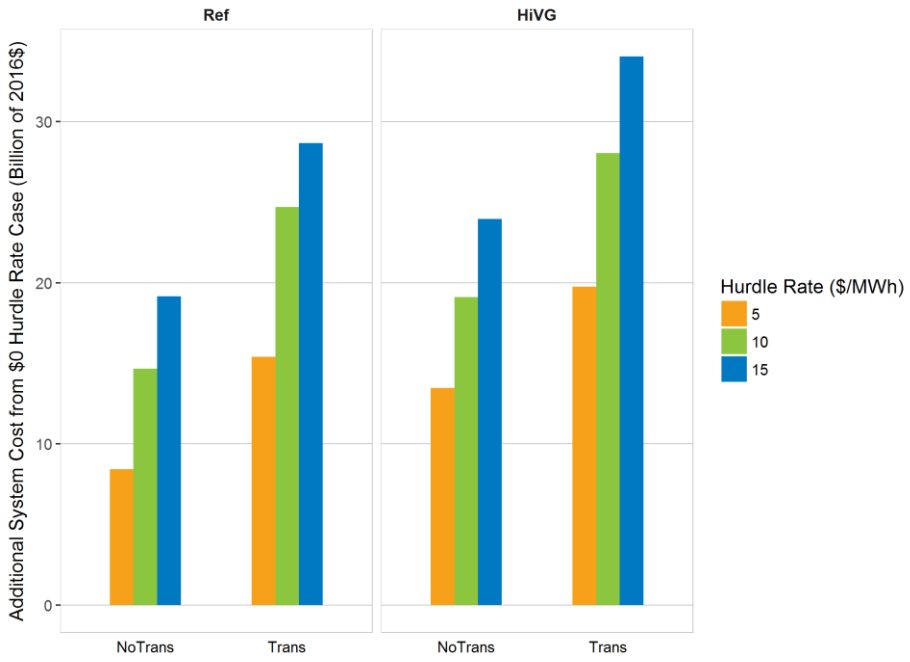


Figure 11. Additional total system cost from no-hurdle rate case for different scenarios.

It is also worth noting that compared to generator investments and operation expenditures, transmission capital costs are only a minor portion of total power system cost (0.7%–0.9% for the Reference scenario and 1.4%–1.7% for the HiVG scenario). When transmission capacity expansion is allowed, higher hurdle rates indicate more difficulties in transferring power, making the whole system less willing to invest in new transmission capacities, and thus resulting in lower transmission costs (Figure 12).

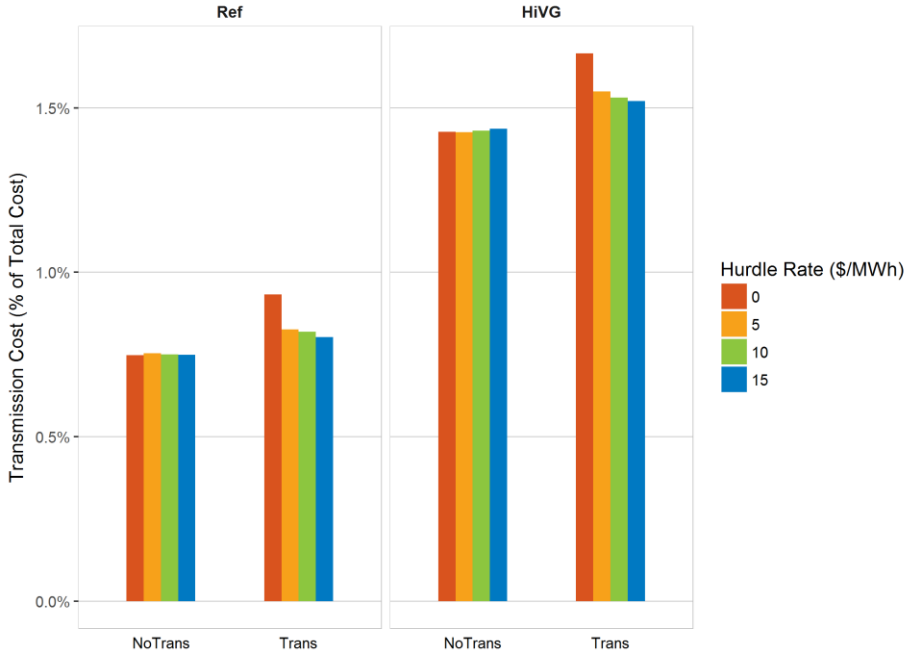


Figure 12. Transmission cost as percentage of total system cost for different scenarios.

4. Conclusions

In this study, we explored how different levels of transmission expansion and interregional cooperation impact VG curtailments, and how the generation mix can respond in order to minimize curtailments. We examined both a Reference and a High VG future scenario, together with constraints on transmission expansion and operation (illustrated by different levels of hurdle rates).

Our results show that VG curtailment increases as VG penetration grows. Despite this, overall curtailment levels remain relatively low, even under our High VG case. Curtailments under different transmission assumptions are very similar, mainly because the model builds more flexible conventional plants and chooses locations for VG closer to load centers. Under a more restricted transmission system—e.g., limited transmission expansion and higher transmission hurdle rates between transmission regions—reliance on NG-CC and solar capacity increases, while investment and utilization of NG-CT, wind, and coal capacity decrease. Such changes in the capacity and generation mix allow the system to increase grid flexibility and local generation, which counterbalances the transmission availability constraints and thus mitigates VG curtailment levels.

Although an adjusted generation mix can help mitigate curtailments when transmission is not available, such integration requires higher cost local generation and results in higher total system costs. Additional regional cooperation among balancing areas, RTOs, or other organizations has the potential to increase the system efficiency and reduce economic losses that created by limitations in the ability to reduce curtailment through exports.

The curtailment values presented here serve only as an estimate. As a capacity expansion model, ReEDS does not have a detailed representation of market operations across RTOs or firm behavior, and it has limited capabilities to provide more resolved operational-level analysis. Thus, valuable future work could include exploring 1) the dynamic interactions of increasing grid flexibility and improving transmission availability using more detailed production cost and unit commitment models, and 2) the optimal combination of different approaches to reduce curtailment with the lowest economic losses.

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