A reduced-form approach for representing the impacts of wind and solar PV deployment on the structure and operation of the electricity system

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Abstract

In many climate change mitigation scenarios, integrated assessment models of the energy and climate systems rely heavily on renewable energy technologies with variable and uncertain generation, such as wind and solar PV, to achieve substantial decarbonization of the electricity sector. However, these models often include very little temporal resolution and thus have difficulty in representing the integration costs that arise from mismatches between electricity supply and demand. The global integrated assessment model, MESSAGE, has been updated to explicitly model the trade-offs between variable renewable energy (VRE) deployment and its impacts on the electricity system, including the implications for electricity curtailment, backup capacity, and system flexibility. These impacts have been parameterized using a reduced-form approach, which allows VRE integration impacts to be quantified on a regional basis. In addition, thermoelectric technologies were updated to include two modes of operation, baseload and flexible, to better account for the cost, efficiency, and availability penalties associated with flexible operation. In this paper, the modeling approach used in MESSAGE is explained and the implications for VRE deployment in mitigation scenarios are assessed. Three important stylized facts associated with integrating high VRE shares are successfully reproduced by our modeling approach: (1) the significant reduction in the utilization of non-VRE power plants; (2) the diminishing role for traditional baseload generators, such as nuclear and coal, and the transition to more flexible technologies; and (3) the importance of electricity storage and hydrogen electrolysis in facilitating the deployment of VRE.

1 Introduction

Climate change mitigation scenarios suggest a large role for renewable energy in decarbonizing the electricity sector [1, 2]. In particular, the long-term energy-economy-climate models with which these scenarios are evaluated rely heavily on variable renewable energy (VRE) technologies, which include wind and solar photovoltaics (PV) that are intermittent and non-dispatchable. However, power systems with significant VRE deployment require a different technology mix and operation than a conventional system dominated by a mix of dispatchable and baseload generators [3]. For example, the integration of VRE is expected to entail more backup capacity to ensure peak demand is met, more flexibility to address increased fluctuations in power supply, and more storage and/or power-to-gas to absorb curtailment. The costs of implementing these structural and operational changes as well as the transmission upgrades required to accommodate VRE are termed integration costs and can be significant [3, 4]. Hirth et al. estimates the integration costs associated with a wind generation share of 30-40% to be 25-35 €/MWh, or as large as 50% of generation costs [5]. Thus, modeling efforts that assess low-carbon futures must capture the impacts of VRE integration on power system structure and operation to more accurately represent the economics of VRE deployment.

Quantifying these impacts typically requires detailed power systems models with high temporal resolution that are capable of capturing the structural and operational changes necessary to ensure the matching of generation and load given simulated VRE deployment and demand [6]. In contrast, long-term energy-economy-climate models are intended to study long-term, global, and multi-sector energy system transformations and thus often sacrifice temporal detail to maintain their large scope and technological detail. These models often operate at decadal time steps and incorporate electricity demand as a single value representing average annual load [7]. The use of a flat load curve tends to overemphasize baseload generation and underestimate the cost of VRE generation. Thus, simplified approaches are needed that that can simulate the impacts and costs of VRE integration, but which do not rely on hourly resolution. Following Hirth et al. [5], these approaches should capture three important stylized facts associated with high VRE shares: (1) the *utilization effect* in which the utilization of non-VRE power plants declines as capacity reserve services increase in importance; (2) the *flexibility effect* in which the need for increased system flexibility drives a transition from inflexible baseload power plants to more flexible technologies; and (3) the substantial role for electricity storage and power-to-gas in managing curtailment and enhancing system flexibility [8, 9].

A few approaches have been implemented for incorporating VRE integration costs and/or constraints into energy-economy-climate models [1]. The simplest solution has been to impose an upper limit on the share of total electricity generation that can be supplied by VRE in an attempt to restrict VRE deployment to a level at which integration costs are small (e.g., 15% generation share). Another solution is to introduce an explicit cost markup that increases with the share of VRE (see e.g. [10]). However, even if this cost markup accurately represents the additional cost of introducing VRE, this approach does not capture the structural and operational impacts on the non-VRE portion of the electricity system (e.g., reduced baseload generation, increased backup capacity and storage).

To address these impacts, Sullivan et al. introduces two system reliability constraints in the MESSAGE model to capture the impact of VRE deployment on (1) the capacity required to meet peak load and contingency events (capacity reserve) and (2) system flexibility (operating reserve) [11]. These constraints successfully endogenize the impacts of VRE deployment on the structure and operation of the electricity system in a plausible way, but the parameterization relies on simulations with detailed power sector dispatch models and is thus not easily reproducible. In addition, the approach is limited to wind generation and is not differentiated by region. Ueckerdt et al. proposes the use of residual load duration curves (RLDCs)[1] to quantify the structural changes and curtailment impacts associated with VRE deployment [12, 13]. RLDCs represent the duration of residual load within a region that must be met by non-VRE power sources and thus can be used to estimate the capacity value of VRE technologies, the amount of VRE curtailment, and the impacts on non-VRE plant utilization as the share of VRE increases.

This paper describes a hybrid approach for incorporating VRE integration challenges into a long-term global energy systems model, MESSAGE [14-17] (see supplementary material for more details), and is part of a special issue on the representation of VRE integration in integrated assessment models [18]. This hybrid approach uses RLDCs, as described in Ueckerdt et al. [19], to improve and increase the regional differentiation of the parameterizations of the system reliability constraints already introduced by Sullivan et al. [11]. Specifically, RLDCs are used to parameterize the impacts of VRE deployment on VRE curtailment, non-VRE flexibility requirements, and the capacity values of wind and solar PV. In addition, updates to the resource potentials for wind and solar technologies and the implementation of flexible and baseload modes of operation for thermal power plants are described. Two scenarios, with and without climate policy, are explored to assess the impacts of VRE deployment on the structure and operation of the electricity system. In addition, a scenario with climate policy, but using the previous Sullivan et al. parameterization is included to highlight how the updated parameterization impacts model results.

2 Enhancing the Representation of VRE in MESSAGE

The renewable technologies that pose challenges for the reliability of the electricity system are defined in MESSAGE as concentrating solar power (CSP), utility-scale solar photovoltaic (PV), and onshore and offshore wind. Two CSP technologies are modeled, including: (1) a flexible plant with a solar multiple of one and 6 hours of thermal storage and (2) a baseload plant with a solar multiple of three and 12 hours of storage. Both plants assume parabolic trough technology with wet cooling and molten salt storage. Because CSP technologies include thermal storage, it is assumed that they do not impose short-term impacts on system reliability [20], but rather their impact results from long-term seasonal variation in generation. In contrast, utility-scale solar PV and wind turbines suffer from intermittent and unreliable generation and thus impose much more significant challenges for the electricity system.

RLDCs provide the residual load after subtracting VRE generation for a particular VRE share and thus give an indication of the magnitude and duration of load that must be provided by non-VRE technologies. Ueckerdt et al. [19] describes the derivation of the RLDCs used in this study. Individual RLDCs are available for eight regions[2] and, within each region, for all combinations of solar PV and wind generation

[1] RLDCs are derived by subtracting VRE generation from electricity load for every point in time using high temporal resolution regional datasets. The resulting residual load is then sorted in descending order.

[2] RLDCs are available for Africa, the United States of America (USA), the European Union (EU), China, India, Japan, Brazil, and the Middle East. These RLDCs were paired with the MESSAGE regions as follows: Africa (Sub-Saharan Africa), USA (North America), EU (Western Europe, Central and Eastern Europe, and Former Soviet Union), China (Centrally Planned Asia/China and Other Pacific Asia), India (South Asia), Japan (Pacific OECD), Brazil (Latin America

(before curtailment) in share increments of 3% between 0 and 45% wind/solar PV shares and, additionally, in 10% share increments between 0 and 130% solar PV/wind shares. These RLDCs are derived using regional hourly time series data for VRE supply and load, assuming no constraints on electricity transmission (i.e., using a copper-plate assumption). Residual load is provided in 10-hour bins for the period of one representative year and is sorted in descending order to derive the RLDC. Examples of RLDCs for North America are illustrated in Figure 1.

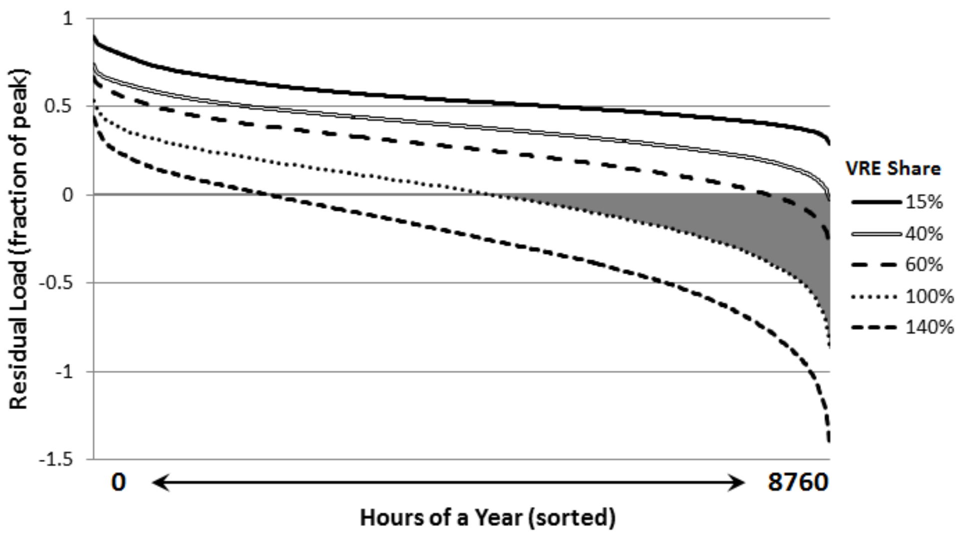

Figure 1: Residual load duration curves for increasing VRE shares between 15% and 140% of total annual load before curtailment in the United States. These curves assume a wind/solar PV mix of 80% wind and 20% solar PV. The grey area is the negative residual load in the 100% VRE share RLDC and represents the portion of VRE generation that would be curtailed at this share.

Using a set of RLDCs spanning a range of VRE shares, reduced-form relationships between VRE deployment and several integration impacts can be approximated and introduced into global energy systems models to better represent structural and operational changes in the electricity sector. Specifically, RLDCs can be used to quantify the impacts of increasing VRE shares on VRE curtailment, the capacity values of VRE technologies, and system flexibility requirements [12]. The methods developed for utilizing RLDCs to parameterize these system impacts are described in sections 2.1 to 2.3. Note however that the copper-plate assumption that underlies the derivation of the RLDCs precludes their use for examining transmission constraints and grid-related integration costs. Although grid-related integration challenges can be significant [5], they are difficult to examine without spatially-explicit models and are thus not considered in this study.

In this section, we describe updates to the representation of VRE in MESSAGE that build upon the previous work described in Sullivan et al. [11]. In particular, we describe innovative methods for using RLDCs to develop region-specific parameterizations of the impacts of VRE deployment on VRE

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and the Caribbean), Middle East (Middle East and North Africa). See supplementary material for list of countries within each MESSAGE region.

curtailment (section 2.1), solar PV and wind capacity value (section 2.2), and the flexibility of non-VRE generation (section 2.3). In addition, we describe the updated resource potentials for wind and solar technologies that were introduced into MESSAGE (section 2.4).

2.1 Electricity Curtailment

Curtailment occurs when excess electricity is generated that cannot be used or stored and is thus wasted. It is generally avoided through careful planning and the operation of dispatchable power plants, which can quickly adjust to changes in demand. However, the introduction of variable renewable energy (VRE), which is characterized by generation that is intermittent and non-dispatchable, can make planning difficult and result in significant curtailment, especially when coupled with inflexible baseload generators. In this section, we describe a method for representing short-term and seasonal curtailment impacts associated with increasing VRE share.

This approach utilizes residual load duration curves (RLDCs) across a range of VRE shares from 0% to 130% wind/solar PV to parameterize curtailment in each region. Since the regional RLDCs quantify the residual load after accounting for VRE generation in each hour of a representative year, curtailment can be defined as the amount of negative residual load, or VRE oversupply, in a given RLDC (Figure 1). Negative residual load indicates that VRE generation alone exceeds electricity demand and thus this oversupply is independent of the flexibility of the remaining generators. Hence, curtailment is defined in the model as the excess VRE generation that cannot be addressed through improving the flexibility of the remaining system. Rather, this curtailment can only be avoided through electricity storage or conversion to hydrogen via electrolysis[3].

Although MESSAGE previously modeled wind and solar PV curtailment independently, the relative mix of these technologies impacts curtailment in a non-linear fashion [8] and hence the updated parameterization quantifies curtailment for representative wind/solar PV mixes. For each region, an iterative process is used to identify the range of wind/solar PV mixes that correspond with those identified in the scenarios (e.g., 72-92% of total VRE generation is projected to be provided by wind in North America). RLDCs that correspond with these mixes are used to quantify how average total VRE curtailment changes with VRE share in each region (Figure 2a). Unlike the previous implementation which considers only one type of curtailment, the average total curtailment is split to distinguish between curtailment that can be addressed with short-term (< 24 hours) versus seasonal storage. Denholm & Hand provide estimates of curtailment with no storage and with 24 hours of storage for the Electricity Reliability Council of Texas (ERCOT) region in the United States [8]. The seasonal fraction of total curtailment is quantified for each VRE share as the fraction of total curtailment that remains in the Denholm & Hand system with 24 hours of storage (i.e., the curtailment that is not addressed with short-term storage)[4]. The seasonal fraction of curtailment increases from 15% at 50% VRE share to 35% at

[3] Note that additional curtailment could result from inflexible generation, such as coal-fired baseload plants, which cannot adjust quickly to intermittent VRE generation. This curtailment is addressed using the operating reserve constraint described in section 2.3.1, which ensures sufficient system flexibility to avoid this type of curtailment.
[4] For lack of regional data, the split between seasonal and short-term curtailment identified in Figure 10 of Denholm & Hand is applied in all regions even though their study was conducted for the ERCOT region in the U.S

100% VRE share and can only be addressed with seasonal storage, which in MESSAGE is represented by hydrogen electrolysis with seasonal storage. The remaining fraction of curtailment is labeled short-term curtailment and can be addressed with either hydrogen electrolysis without seasonal storage or a generic electricity storage technology that provides up to 24 hours of storage[5].

Given the relationship between average seasonal and short-term curtailment and increasing VRE share in each region, the final step is to identify marginal curtailment parameters that capture how seasonal and short-term curtailment increase with each additional unit of VRE generation while accurately representing the average total curtailment values evident in the RLDCs. Step-wise linear functions are used to represent seasonal and short-term curtailment in MESSAGE and are illustrated in Figure 2b for North America (see supplementary material for marginal and seasonal curtailment parameters (Table SM2) and a comparison with the previous implementation). In each region, six deployment steps are used to model the increase in both marginal seasonal and short-term curtailment as VRE generation grows. These deployment steps are implemented as the following constraints, which must be met in each region and time period.

Short-term curtailment:

$$(1)\quad Elec_{VRE} - \frac{1}{WCU_X} Elec_{WCURT_X} - \frac{1}{WCU_X} Elec_{STOR_X} - \frac{1}{WCU_X} Elec_{H2_X} \leq Elec_{TOT} * (X)$$

Seasonal curtailment:

$$(2)\quad Elec_{VRE+CSP} - \frac{1}{SCU_X} Elec_{SCURT_X} - \frac{1}{SCU_X} Elec_{H2ST_X} \leq Elec_{TOT} * (X)$$

where:

$X \in \{0.35, 0.45, 0.55, 0.65, 0.75, 0.85\}$ (VRE share of total electricity generation before curtailment)

$Elec_{VRE}$ = total electricity generated by VRE (solar PV and onshore and offshore wind)

$Elec_{VRE+CSP}$ = total electricity generated by VRE and CSP

$Elec_{TOT}$ = total electricity entering the transmission grid

WCU_x = marginal short-term curtailment parameter for step x

SCU_x = marginal seasonal curtailment parameter for step x

$Elec_{SCURTx}$ = electricity curtailed seasonally in step x

$Elec_{WCURTx}$ = electricity curtailed in the short-term in step x

$Elec_{H2x}$ = electricity in step x that is input to a hydrogen electrolyzer without storage

$Elec_{H2STx}$ = electricity in step x that is input to a hydrogen electrolyzer with storage

$Elec_{STORx}$ = electricity in step x that is input to a generic electricity storage technology

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and assumes a 70/30 wind/solar mix. Note however that Denholm & Hand is only used to identify the fraction of total curtailment that is seasonal. The total curtailment itself is derived by the regional RLDCs.

[5] Electricity storage is modeled in MESSAGE as a single generic technology that is parameterized based on data for compressed air storage (CAS) and provides storage, reserve capacity, and system flexibility with an efficiency of 80% and capital cost ranging from $800/kW in 2010 to $600/kW in 2100.

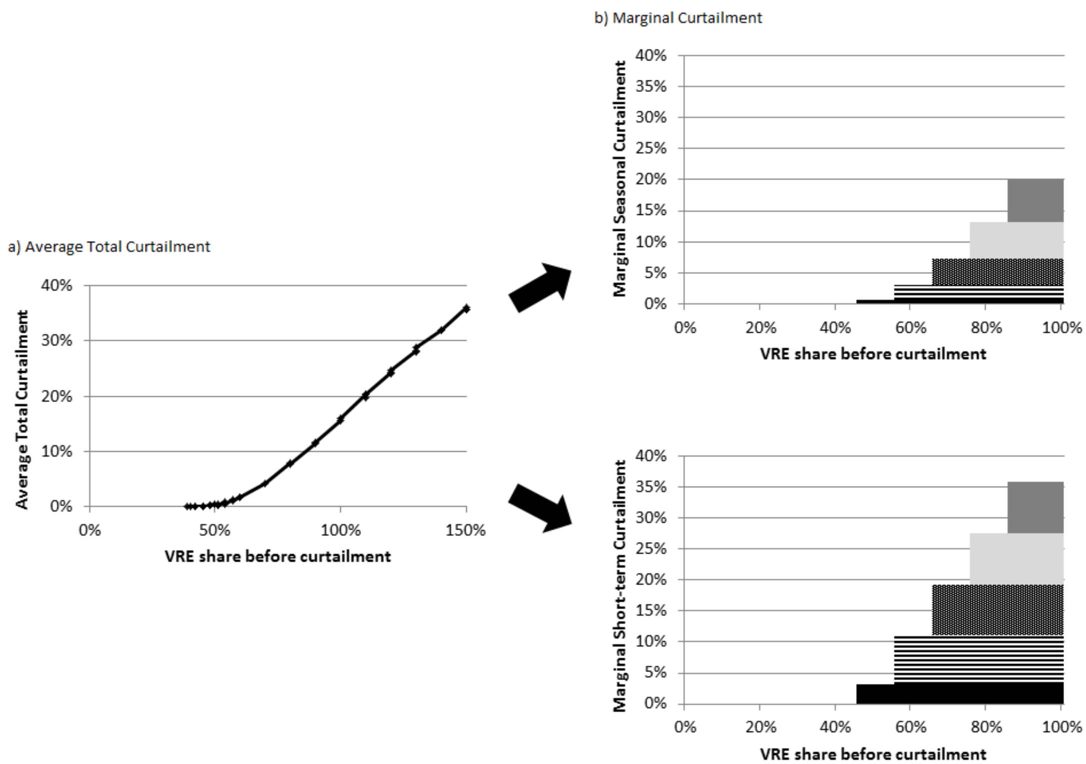

Figure 2: Process of parameterizing seasonal and short-term curtailment from RLDCs using North America as an example. Panel a illustrates the average total curtailment as a function of VRE share as derived directly from the negative residual load found in RLDCs where wind accounts for 72-92% of the VRE share. Panel b exhibits the step-wise linear functions that are used to parameterize marginal seasonal and short-term curtailment in MESSAGE. Note that in North America, curtailment does not begin until the VRE share exceeds 45% (i.e., the first deployment step has no curtailment).

The old MESSAGE implementation of curtailment introduces much larger curtailment that begins at smaller solar PV and wind shares (see Supplementary Figure 2). The marginal curtailment associated with each additional unit of wind and solar PV generation already reaches 35-40% at a wind share of 35% and solar PV share of 18%. In contrast, the updated implementation based on regional RLDCs indicates no curtailment at VRE shares below 45% and a much more gradual introduction of curtailment thereafter. Hence, while the old implementation discourages further investments in solar PV and wind at 18% and 35% shares, respectively, the updated implementation indicates more moderate curtailment.

2.2 Capacity Reserve

Because electricity demand is represented in MESSAGE as a single value in each time period (average annual load), it does not capture the temporal variability of demand or the need for additional capacity to meet peak load and contingency events. Sullivan et al. [11] describes the introduction to MESSAGE of a capacity reserve constraint that ensures that firm generating capacity is sufficient to meet peak load plus contingencies. This section describes updates to the Sullivan et al. approach, including: (1) unique firm capacity requirements for each region and time period and (2) increased transparency and regional specificity of changes in the capacity value, or contribution to firm capacity, of wind and solar PV as their deployment increases.

2.2.1 Firm capacity requirement

In Sullivan et al. [11], the firm capacity requirements are defined as roughly twice average load in all regions. However, it is expected that the ratio between peak and average load will vary among regions and over time as electricity demands change with development. Heinen et al. [21] propose a method for approximating the ratio of annual peak load to annual average load based on the share of total electricity demanded by the residential and service sectors. Given that residential electricity demand tends to fluctuate more than industrial demand, they find that the ratio increases with a growing share of residential demand and can be approximated with the following equation:

$$(3)\quad Peak\ Ratio = \frac{Elec_{Ind} + 2 * Elec_{Res}}{Elec_{Ind} + Elec_{Res}}$$

where $Elec_{Ind}$ is the industrial electricity demand and $Elec_{Res}$ is the residential electricity demand. This equation is used to calculate the peak ratio in each region and time period given the projected residential and industrial electricity demands. As validation, the resulting values in 2010 were compared against the peak ratios calculated directly from the RLDCs and were found to be roughly consistent. However, equation 3 provides a distinct advantage over using the RLDCs since it enables the estimation of unique peak ratios for each region and time period based on projected changes in the share of residential electricity demand. Given the peak ratio, the firm capacity requirement is calculated by adding an additional reserve margin of 20% to cover contingency events (see supplementary material for firm capacity requirements in all regions and time periods; Table SM4).

2.2.2 Capacity value of wind and solar PV

The second update uses RLDCs to quantify how the capacity values of wind and solar PV change with increasing shares. The capacity value is the contribution of a technology to overall system adequacy, which is defined here as a technology's contribution to the firm capacity requirement. Since the firm capacity requirement is the capacity needed to meet peak load and contingency events, a technology's capacity value is the amount of capacity available during peak load. Whereas conventional generating technologies are assumed to contribute their full nameplate capacity to firm capacity, the capacity values of wind and solar PV technologies tend to decline with increasing market share [12, 22-24]. This section describes a reproducible approach to parameterize the relationship between capacity value and market share for solar PV and wind using RLDCs.

At a given wind or solar PV share, the capacity value of the respective technology can be assessed by calculating the peak load reduction evident in the relevant RLDC and calculating the fraction of the technology capacity that contributes to peak load reduction[6]. Capacity values can be derived for all

[6] Peak load is provided in the RLDCs as the average load during the 10 hours with the largest load. The reduction in peak load is the difference between the baseline peak load (i.e., no wind or solar PV) and residual peak load at a specific wind or solar PV share. For example, assuming that baseline peak load is 1 GW, solar PV generation is 0.03 GWyr, and the average capacity factor of solar PV is 20%, we can calculate the equivalent capacity of solar PV as 0.03 GWyr/0.2 yr or 0.15 GW. Then, assuming that the relevant RLDC indicates a peak load reduction of 0.075 GW,

RLDCs in which either solar PV or wind shares are positive, resulting in independent estimations of how capacity values decline with increasing solar PV or wind shares in each region (Figure 3).

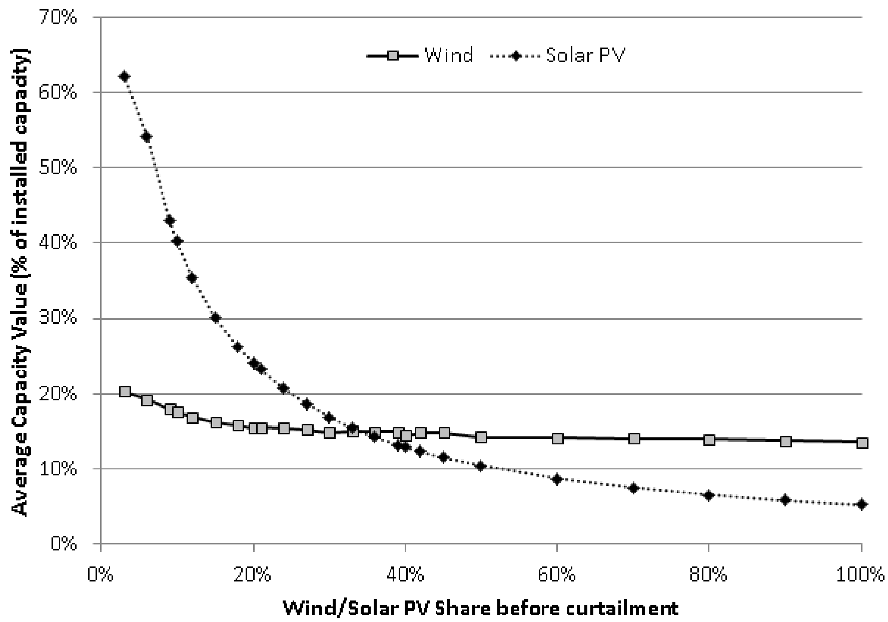

Figure 3: Average capacity value as a function of market share for wind and solar PV using North America as an example.

The relationships between average capacity value and solar PV and wind shares are implemented in each region as stepwise linear supply curves that represent the marginal capacity value with increasing share. Using North America as an example (Figure 4), the supply curves indicate that solar PV generation is well-aligned with peak load at low deployment, but provides very little capacity value beyond a 30% share. In contrast, the capacity value of wind starts at a smaller value, but declines less dramatically with increasing share. The capacity reserve constraint requires that the total of firm capacity in each region and time period is greater than or equal to the firm capacity requirement (equation 4). The equations for defining the supply curve bins and the marginal capacity value coefficients for solar PV (SCV) and wind (WCV) (Table SM5) are provided in the supplementary material.

$$(4)\quad \sum Cap_{Conv} + Cap_{Stor} + \sum\left(CAP_{PV_x} * CF_{PV_x} * SCV_x\right) + \sum\left(CAP_{WIND_x} * CF_{WIND_x} * WCV_x\right) \geq LOAD_{AVG} * FIRM$$

where:

Cap_{Conv} = Capacity of conventional generators (coal, oil, biomass, gas, nuclear, hydro, geothermal, hydrogen, CSP)

Cap_{Stor} = Capacity of generic storage technology

Cap_{PVx} = Capacity of solar PV in step x of solar PV capacity value supply curve

CF_{PVx} = Average capacity factor of solar PV in step x

SCV_x = Marginal capacity value in step x of solar PV capacity value supply curve (fraction of capacity factor)

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the capacity value is estimated as 0.075/0.15 or 50% of installed capacity. Note that the capacity value can be larger than the capacity factor in situations where generation aligns well with peak load.

CAP_{WINDx} = Capacity of wind in step x of wind capacity value supply curve

CF_{WINDx} = Average capacity factor of wind in step x

WCV_x = Marginal capacity value in step x of wind supply capacity value curve (fraction of capacity factor)

$LOAD_{AVG}$ = Average annual load

FIRM = firm capacity requirement as a multiplier of average annual load (includes reserve margin)

Supply curve steps (x) are 0-15%, 15-50%, 50-80%, and >80% VRE share of total generation before curtailment

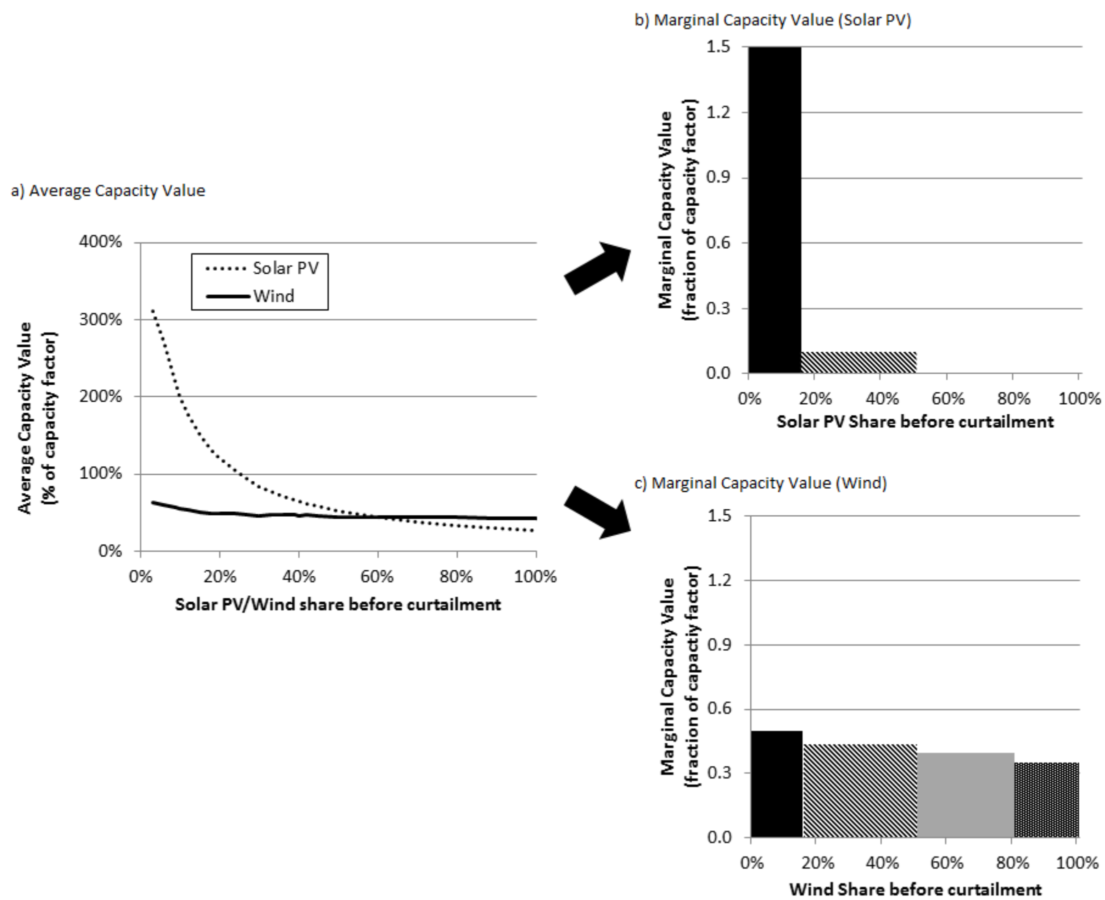

Figure 4: Process of parameterizing wind and solar PV capacity values from RLDCs using North America as an example. Panel a indicates the average capacity value of wind and solar PV as a function of their share as derived directly from the peak load reduction found in the RLDCs. Panel b shows the step-wise linear supply curves that are used to parameterize the marginal capacity values in MESSAGE. Note that marginal capacity value is expressed as the fraction of the average regional capacity factor so a value greater than 1 indicates that a technology provides more than its average load during peak periods.

In contrast to the updated implementation that identifies unique supply curves for each VRE technology and region, the Sullivan et al. approach uses identical supply curves for both solar PV and wind and across all regions. Moreover, while the Sullivan et al. approach generally overestimates solar PV and wind capacity values at low shares compared to the updated implementation, it substantially underestimates the contribution of solar PV and wind to firm capacity at shares above 25% since the marginal capacity value is zero beyond this share (see Supplementary Figure 3). This is particularly true for wind given that the marginal capacity values derived using the regional RLDCs remain above 25% in most regions even at wind shares above 80%. Hence, similar to curtailment, the old implementation is expected to be less conducive to high VRE shares than the updated implementation, particularly when wind and solar PV shares exceed 25%.

2.3 Flexibility requirement

To maintain operational reliability, the electricity system must include an operating reserve, or sufficient flexible generating capacity, that can be made available within a short period of time to meet fluctuations and uncertainty in demand and address unforeseen disruptions in supply. The operating reserve generally includes generating capacity that can quickly ramp its output (spinning reserve) as well idle capacity that can be brought online quickly (non-spinning reserve). To represent the need for an operating reserve in MESSAGE, Sullivan et al.[11] introduced a flexibility constraint that requires that a fraction of the total annual generation is supplied by flexible generating capacity.

(5) $\sum Elec_x * FLEX_x \geq Elec_{TOT} * FLEX_{load}$

where $Elec_x$ is the electricity output from power plant technology x, $FLEX_x$ is the operating reserve, defined here as the flexible fraction of generation that can be supplied by technology x, $Elec_{TOT}$ is the total annual generation, and $FLEX_{load}$ is the system flexibility required to meet fluctuations and uncertainties in demand. Sullivan et al. parameterizes the FLEX coefficients for each technology and load using a simplified unit commitment model of a limited grid. In this parameterization, solar PV and wind generation have negative FLEX coefficients, which suggest that increased VRE deployment introduces more supply intermittency and fluctuation, necessitating a larger operating reserve and more flexibility in the rest of the electricity system. Shortcomings of this parameterization include: (1) the uniform application of the coefficients derived from a limited grid to all regions and (2) the provision of operating reserves from thermoelectric power plants without accounting for the trade-offs, such as larger operating and maintenance (O&M) costs and reduced efficiency and capacity factor[7]. To address these shortcomings, we propose a method to derive region-specific FLEX coefficients for load and variable renewable energy using residual load duration curves and we add two modes of operation for thermoelectric power plants to account for the penalties associated with flexible operation.

2.3.1 Parameterizing the impact of VRE deployment on system flexibility requirements

An RLDC can be used to estimate the fraction of electricity generation that must be supplied by flexible generators at a given VRE share, where VRE includes only solar PV and wind. The first step is to identify the fraction of peak load that can be supplied by baseload generation (black line in Figure 5) while restricting curtailment from baseload to an acceptable level (defined here as 1% of total generation and shown as the black area in Figure 5). All generation below the black line in Figure 5 is capable of being generated by inflexible baseload and all generation above the line requires flexible generation. The flexible generation estimated from the load duration curve with no VRE deployment (Figure 5a) is not

[7] The capacity factor is the fraction of the year during which a generating technology operates (i.e., the total annual full-load hours divided by the total hours in one year).

influenced by the structure of the supply system and thus represents the flexible fraction of total generation that must be supplied to meet fluctuations and uncertainty in demand ($FLEX_{load}$).

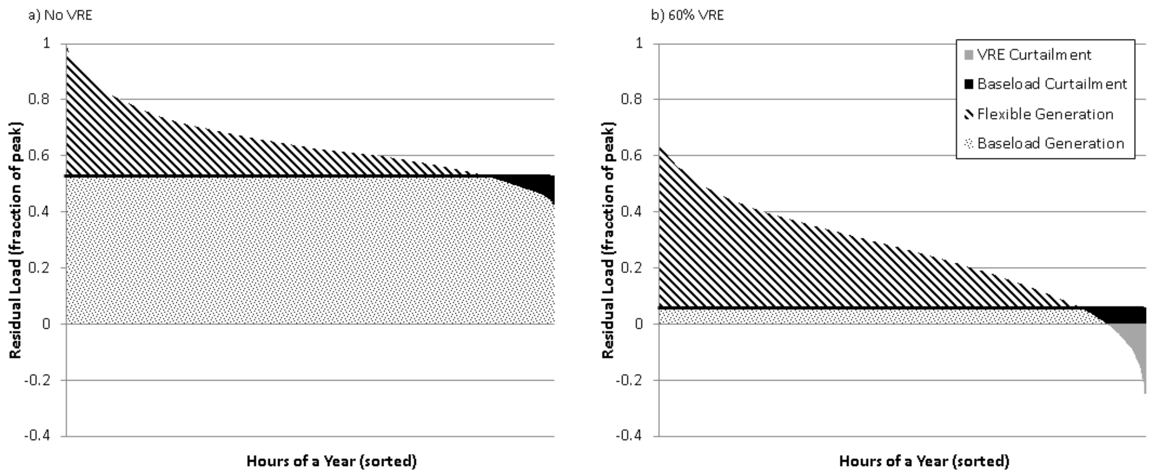

Figure 5: Illustration of method for estimating the required flexible share of electricity generation based on RLDCs, using examples of (a) no VRE and (b) 60% VRE in North America (83/17 wind/solar PV mix). The black line indicates the fraction of peak load that can be met by baseload generation while restricting curtailment from baseload to less than 1% of total generation.

Using a series of RLDCs with increasing VRE shares, we estimate how the flexible fraction of non-VRE generation changes with increasing VRE deployment[8]. Using North America as an example, Figure 6a indicates that non-VRE electricity generation must rapidly become more flexible as the VRE share expands if significant curtailment from inflexible generation is to be avoided. For example, non-VRE flexible electricity generation increases to 90% at 70% VRE share and then levels off and saturates at 100% when the VRE share (before curtailment) reaches 150%[9]. This non-linear relationship suggests that the marginal increase in flexible generation per unit of VRE generation first increases, but then declines at VRE shares above 50-60%. This is confirmed when examining the relationship between the VRE share and the flexible share of total generation (Figure 6b). It is evident in this figure that each unit of additional VRE generation requires more flexible generation up to about 50% VRE share (before curtailment), but then requires less flexible generation per unit of VRE as non-VRE generation becomes a smaller share of total generation (even though the remaining non-VRE share is nearly all flexible).

Since the flexibility requirement increases non-linearly with VRE generation, a mixed integer implementation is required. Specifically, the response of non-VRE flexible generation to increasing VRE generation is modeled with a piecewise linear supply curve with binary variables that ensure that the "lowest cost" piece is only accessed within the appropriate VRE deployment bin. This approach is necessary to prevent the flexible share of non-VRE generation from exceeding 100%, which would force excess electricity supply at large VRE shares. The flexibility coefficients ($FLEX_{VRE}$) within each VRE

[8] Similar to the assessment of curtailment, solar PV and wind deployment are considered jointly so RLDCs that are consistent with the range of wind/solar PV mixes found in each region are used to assess non-VRE flexibility requirements.
[9] A 150% VRE share before curtailment in North America corresponds to a 96% VRE share after curtailment as there is significant oversupply of VRE at high shares.

deployment bin are derived from the RLDCs available for each region and are listed in the supplementary material (Table SM7) along with the equations describing the mixed integer approach.

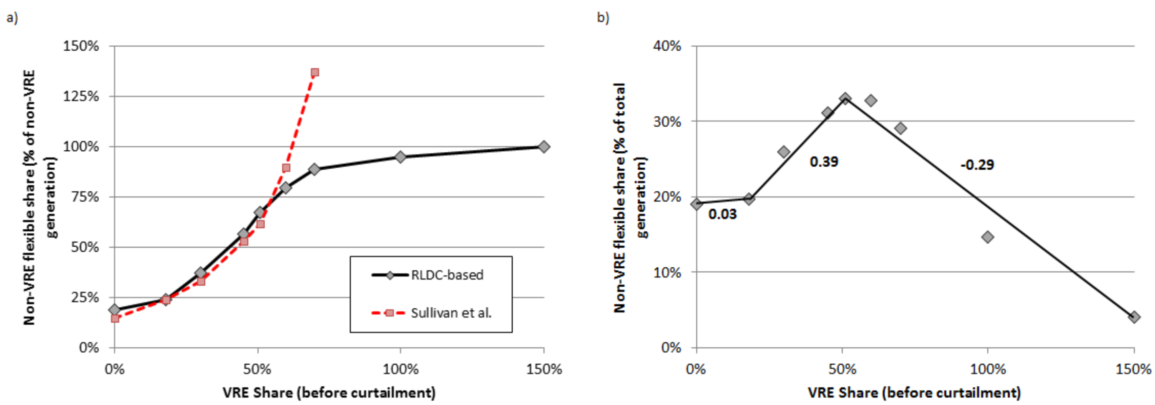

Figure 6: Relationships between the VRE share of total generation and the flexible share of (a) non-VRE generation and (b) total generation for North American RLDCs where wind accounts for 72-92% of VRE generation. The numbers in (b) are the slopes of the individual pieces of the piecewise linear supply curve used to represent the relationship between VRE generation and flexible generation. The negatives of these values are used as the VRE coefficients in the flexibility constraint (i.e., $FLEX_{VRE}$). In panel a, the RLDC-based relationship (black solid line) is compared with the actual trajectory resulting from the Sullivan et al. approach (red dashed line).

In contrast to the updated implementation that identifies unique supply curves for representative solar PV/wind mixes in each region, the Sullivan et al. parameterization uses identical supply curves for both solar PV and wind and across all regions (see supplementary material). Moreover, Sullivan et al. does not employ a mixed integer approach and thus the marginal non-VRE flexibility requirement increases with VRE share. As a result, the fraction of non-VRE generation that must be flexible exceeds 1 at 60-65% VRE share, meaning that excess electricity generation is required beyond this share (Figure 6). Although the Sullivan et al. parameterization yields similar non-VRE flexible shares up to a 50-55% VRE share, it diverges from the updated parameterization beyond this point as the non-VRE flexible share continues to increase rather than saturating. Given that excess electricity generation is required beyond a 60-65% VRE share, the Sullivan et al. parameterization is again less conducive to the deployment of large VRE shares relative to the updated parameterization.

2.3.2 Improving the representation of flexible thermoelectric plant operation

Most power plant technologies can be operated to provide some operating reserve. However, flexible operation can have significant impacts on the plant O&M cost, efficiency, and capacity factor; particularly for thermoelectric plants [25-27]. To reflect these impacts, thermoelectric technologies have been updated to include two options for plant operation: baseload and flexible[10]. Baseload operation provides no operating reserve and assumes a capacity factor of 85%, whereas flexible operation provides a portion of generation as operating reserve, but incurs penalties in the form of increased O&M cost and reduced efficiency and capacity factor. The amount of operating reserve that

[10] In each time period and region, the model has the choice to operate the installed capacity as baseload, flexible, or a mix of the two. Thus, for a given capacity, the model identifies the optimal mix of baseload and flexible operation that minimizes cost while meeting the flexibility requirement.

can be provided by a particular technology is estimated as the difference between its baseload capacity factor and its minimum load (see Supplementary Figure 5). To safeguard the system from positive and negative scheduling error, both incremental (increased generation) and decremental (reduced generation) operating reserve is required. Effects of scheduling incremental and decremental reserve is included in the model by assuming the capacity factor of plants in flexible mode occurs at the midpoint between the baseload capacity factor and the minimum load (i.e., incremental and decremental reserves are assumed symmetric). O&M cost penalties accrue due to the increased wear-and-tear from ramping units quickly and starting and stopping units more frequently. These costs are derived from the cold start-up and load following costs reported in Kumar et al. [25].

Assumptions relevant to flexible thermoelectric plant operation are listed in Table 1. Coal and biomass gasification power plants are assumed to operate only in baseload mode (i.e., they provide no operating reserve), whereas hydropower, geothermal, CSP, electricity storage, and combustion turbines are assumed to be flexible in standard operation and thus always provide some portion of their generation as operating reserve.

Table 1: Operating reserve, capacity factor, O&M cost, and efficiency penalty assumptions for flexible operation of thermoelectric power plants

Power Plant Type	Operating reserve coefficient (fraction of generation)	Capacity factor (fraction of installed capacity)	Cycling-related variable O&M cost ($/MWh)[1]	Efficiency Penalty (% reduction)[2]
Coal/biomass combustion and gas combined-cycle	0.53	0.63	0.58 - 1.56	6%
Gas and oil combustion	0.86	0.49	9.24 - 9.36	8%
Gas/H_2 combustion turbine	1	0.43	12.47	N/A
CCS and Nuclear	0.20	0.77	1.28 - 1.39	14%
Coal/biomass gasification	0	0.85	N/A	N/A
Hydropower	0.66	0.42	N/A	N/A
Geothermal	0.32	0.70	N/A	N/A
Flexible CSP	1	Resource-dependent	N/A	N/A
Baseload CSP	0.50	Resource-dependent	N/A	N/A
Utility-scale H_2 fuel cell	1	0.35	N/A	N/A
Electricity storage	1	0.25	N/A	N/A

[1] Ranges are provided to represent variation among technologies in each category.
[2] For plant types that always provide flexibility, efficiency and O&M cost penalties associated with cycling are not added, but rather are implied in the standard efficiency and cost estimates.

2.4 Technologies and Resource Potentials

As part of the effort to improve the representation of renewables in MESSAGE, the resource potentials were updated based on recent high resolution estimates for solar PV and CSP [10] and onshore and offshore wind [28]. The solar resource data are available at the national level and are categorized by resource quality as represented by capacity factor. For implementation in MESSAGE, the national level estimates are aggregated to each MESSAGE region and into a reduced set of capacity factor categories (see supplementary material for regional definitions and resource potentials by capacity factor; Tables SM9-11). The resource potentials for solar PV and CSP are quantified independently since CSP can only use direct normal irradiance (DNI) while PV can also use diffuse light[11]. Both CSP technologies share the same resource, but the capacity factors are much lower for the technology with less storage. However, the potential remains nearly identical since plants with less storage have a smaller footprint and thus more capacity can be built per unit area.

The onshore and offshore wind resource potentials are independent and are provided at the national level and categorized according to wind class. The onshore wind potential is further categorized by distance to load and the offshore potential is categorized by distance to shore and water depth. For use in MESSAGE, the national estimates are aggregated for each MESSAGE region and only wind classes 3 and above are incorporated into the model. Furthermore, only onshore potential within 161 km (100 miles) of demand centers and offshore potential within 37 km (20 nautical miles) of shore are considered[12]. The capacity factors associated with each wind class vary by region and are calculated from the independent power and energy potentials provided in the dataset (see supplementary material for regional capacity factor and resource potential assumptions; Tables SM12-14).

Given sufficient resource potentials, the deployment of renewable technologies is largely determined by their relative costs compared with other electricity generating technologies. In MESSAGE, onshore wind remains the lowest cost VRE technology throughout the century with investment costs declining to $781/kW in 2100 (Figure 7). Thus, onshore wind is preferred to other VREs in our scenarios, but it is still subject to resource, integration, and market deployment constraints, which enables the deployment of other technologies. Tables SM15-19 in the supplementary material provide the overnight capital costs for wind and solar technologies.

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[11] MESSAGE assumes that the full CSP and PV potentials are available to each respective technology and thus does not account for potential double use of the same resource and land area. However, this is not critical in the current version of the model as CSP is minimally deployed as a result of its high cost.

[12] This is roughly consistent with the solar resource potentials, which are limited to resources within 100 km of load. Moreover, MESSAGE has a fixed transmission cost for all generation and thus transmission costs associated with very distant resources would not be accurately represented within the model.

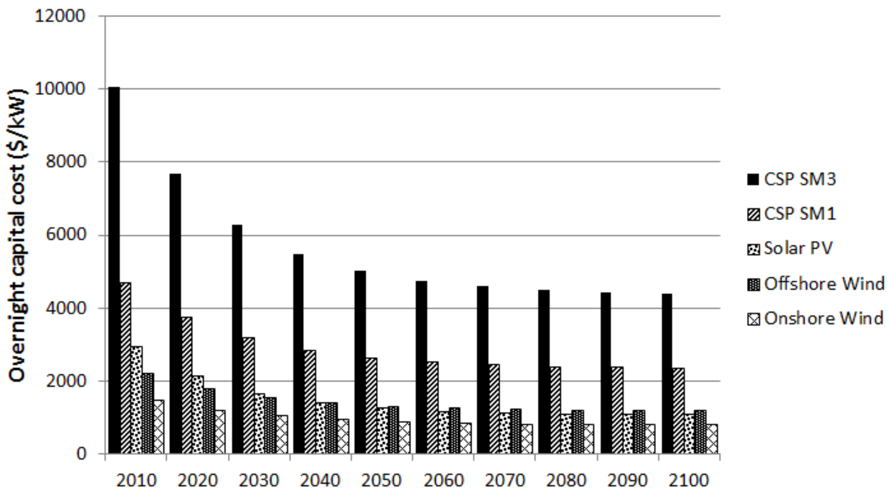

Figure 7: A comparison of overnight capital costs ($/kW) in the North America region for wind and solar technologies

3 Impacts of VRE deployment on system structure and operation

To examine the impacts of the integration constraints described in section 2 on the structure and operation of the electricity system under large VRE shares, two scenarios were evaluated. The first scenario is a reference scenario, entitled “Baseline”, in which the energy system develops in the absence of climate policy, but with access to a full portfolio of technologies. The second scenario, entitled “Tax30”, also includes a full portfolio of technologies, but imposes a carbon tax that begins at $30/ton CO_2 (2005USD) in the 2021-2030 period and increases by 5% per year thereafter. Tax30 was selected because the high carbon price induces not only a large share of VRE, but also gives insight into how a carbon tax impacts the remaining system and its ability to integrate VRE. The baseline scenario achieves a VRE share of approximately 60% in 2100 (Figure 8) and thus the two scenarios enable a comparison of the way in which the electricity system adapts to a relatively large VRE share with and without a carbon tax. In addition, a Tax30 scenario using the previous Sullivan et al. parameterization is presented in order to clarify how the updated implementation influences VRE deployment relative to the old implementation. The “Old Integration” scenario uses the updated resource potentials and technology costs so that the only differences with Tax30 are the parameterizations of VRE curtailment, system flexibility requirements, and capacity reserves.

Figure 8 llustrates the transformation of global electricity generation in each scenario and provides some useful insights into the impacts of VRE deployment on the electricity system. In the baseline scenario, VRE generation increases gradually over the century, reaching 60% of gross generation by 2100, and is composed almost exclusively of wind generation. In the absence of a carbon tax, remaining generation is supplied primarily by gas and coal. Hydropower generation remains nearly constant, resulting in a reduction in its share of generation over time. With the decline in the cost of hydrogen fuel cells, the share of hydrogen-based electricity generation from decentralized and utility-scale fuel cells increases, providing some additional flexibility as VRE share increases. Some electricity storage is used to absorb the small amount of VRE generation that would otherwise be curtailed (e.g., 3% in 2100).

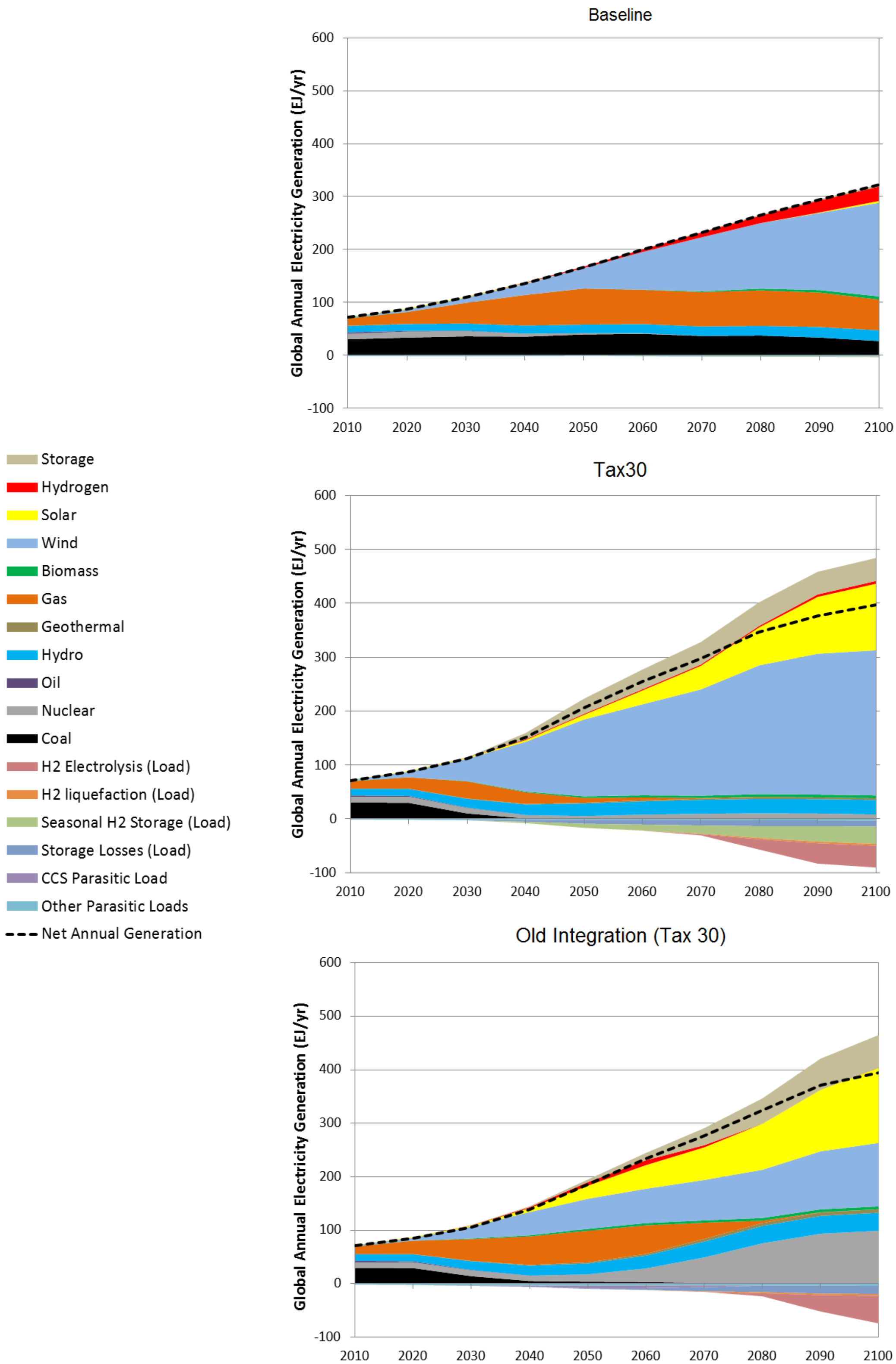

Figure 8: Global annual electricity generation in the Baseline (top), Tax30 (middle), and Old Integration (bottom) scenarios. Note that Solar includes both solar PV and CSP. Solar PV accounts for nearly 100% of total solar generation in Tax30, but only 50% in Old Integration.

As expected, electricity generation is larger in Tax30 since the industrial and transportation sectors of the economy electrify more significantly to reduce emissions when a carbon tax is implemented [29]. The VRE share of gross generation increases rapidly to 63% by 2040 and 83% by 2100 with approximately 70% of VRE from wind and 30% from solar PV in 2100. As the VRE share expands, hydrogen electrolysis absorbs a large share of the VRE generation that would otherwise be curtailed (e.g., 22% of VRE generation in 2100). In addition, electricity storage is used to both absorb VRE over-generation and provide flexibility to the system. In general, increasing VRE deployment shifts remaining generation to low-carbon flexible technologies, such as hydropower and electricity storage. Carbon-intensive fossil technologies (e.g., coal and gas) are phased out completely and low-carbon technologies with relatively low flexibility (e.g., nuclear and biomass with CCS) account for less than 3% of gross generation in 2100.

In contrast, the Old Integration scenario using the Sullivan et al. parameterization indicates a much smaller VRE share than the Tax30 scenario with the updated parameterization. In the Old Integration scenario, the VRE share of gross generation increases to 40% by 2050, but then levels off and reaches only 44% by 2100, which is even smaller than the VRE share in the baseline scenario with the updated parameterization. As noted in section 2, the Sullivan et al. parameterizations of curtailment, capacity value, and flexibility are much less favorable for VRE deployment than the updated parameterizations based on regional RLDCs. For example, the marginal curtailment associated with VRE increases precipitously at solar PV and wind shares greater than 18% and 35%, respectively. Moreover, the marginal capacity values of both technologies decline to zero beyond a 25% share of gross generation, necessitating one unit of backup capacity for each additional unit of VRE capacity. Finally, the flexible share of non-VRE generation extends beyond 100% when the combined VRE share exceeds 60-65%, meaning that excess electricity generation becomes necessary to meet system flexibility requirements.

It is perhaps then not surprising that the shares of solar PV and wind generation reach only 16% and 28%, respectively, by 2100 in the Old Integration scenario. The fact that the share of VRE levels off at 44% of gross generation suggests that this is the share at which integration costs render VRE uncompetitive with other low carbon technologies. Whereas nuclear and CSP account for less than 2% of gross generation in 2100 in the Tax30 scenario, they comprise 19% and 16% of gross generation, respectively, in the Old Integration scenario. Nuclear and CSP are expanded to provide firm capacity and low GHG emissions as the capacity value of VRE declines. Yet nuclear provides no flexibility and thus large amounts of storage are required to meet the flexibility requirement when nuclear is deployed. In fact, the quantity of electricity absorbed by storage and H_2 electrolysis technologies is nearly five times larger than that required for VRE curtailment alone, which suggests that nearly all of the electricity storage is used to store curtailed electricity from inflexible nuclear baseload power plants. Thus, above a VRE share of approximately 44% in the Old Integration scenario, building CSP and nuclear with electricity storage appears less expensive than further expanding VRE.

The following sections focus on the Baseline and Tax30 scenarios and describe the impacts of VRE deployment on the operation and structure of the electricity system with and without carbon taxes, including the impacts on: (1) curtailment; (2) flexible generation, (3) system capacity, and (4) power plant utilization.

3.1 VRE curtailment

As discussed in section 2.1, VRE curtailment is defined as the portion of VRE generation that exceeds demand during a year. The regional RLDCs indicate that VRE curtailment is essentially zero prior to 40% VRE share and then gradually increases to 15-30% when the VRE share increases to 100%. A portion of this curtailment occurs over short periods (< 24 hours) and can be addressed using electricity storage and hydrogen electrolysis. The remainder of the curtailment occurs seasonally and can only be addressed in MESSAGE using hydrogen electrolysis with seasonal storage. Figure 9 illustrates the theoretical short-term and seasonal curtailment that would occur in the absence of the deployment of storage and/or H_2 electrolysis for the VRE shares in each decade of the Baseline and Tax30 scenarios. Theoretical total curtailment remains below 4% of VRE generation in the baseline, but increases from 8% to 22% of VRE generation in Tax30[13]. Figure 9 also indicates the electricity input to H_2 electrolysis and electricity storage technologies and represents the curtailed electricity that is avoided through the use of these technologies. In both scenarios, it is less expensive to deploy these technologies than to curtail electricity. For example, the electricity input to H_2 electrolyzers with seasonal storage perfectly matches the theoretical seasonal curtailment. In addition, the electricity input to electricity storage and H_2 electrolysis without seasonal storage exceeds the theoretical curtailment in both scenarios.

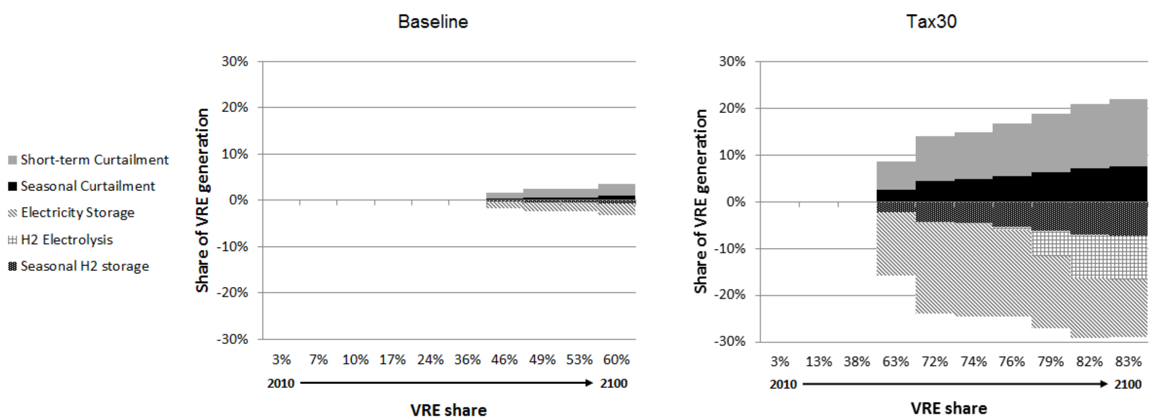

Figure 9: Theoretical seasonal and short-term VRE curtailment and electricity input to technologies that absorb curtailment (H_2 electrolysis and electricity storage) as a function of the VRE share of gross generation before curtailment. Theoretical curtailment is represented by positive values and the electricity input to technologies that absorb this curtailment is given as negative values. Values are provided for Baseline (left) and Tax30 (right) scenarios and VRE shares are those associated with each decade between 2010 and 2100. Values for the Old Integration scenario are provided in Supplementary Figure 6.

Short-term curtailment is addressed entirely using electricity storage in the baseline while Tax30 uses both storage and H_2 electrolysis. A major difference between the two scenarios is the extent to which electricity storage exceeds the storage required to address VRE curtailment[14]. While 1-6% of electricity

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[13] For similar VRE shares (60% in Baseline and 63% in Tax30), the theoretical total curtailment is roughly double in Tax30. In the absence of a carbon tax, the model uses VRE in regions in which the curtailment as well as technology and integration costs are lowest. However, with a carbon tax, the model is incentivized to reduce emissions in all regions and thus deploys VRE in regions with larger curtailment. Thus, the difference between scenarios is the result of differences in the regional distribution of VRE deployment.

[14] The excess electricity storage indicates that short-term curtailment is a non-binding constraint since storage is needed to provide other services like firm capacity and system flexibility.

storage is not used for VRE curtailment in the baseline, 45-65% is used for other purposes in Tax30[15]. Since the generation from the storage technology is fully flexible, electricity storage is also deployed to provide non-VRE system flexibility. Thus, even in the time period from 2040-2060 (63-74% VRE share) less than 50% of electricity storage is used to store curtailed VRE. Given the rapid increase in VRE, the electricity system has insufficient time to transition to more flexible generators and thus achieves the required flexibility by storing a portion of inflexible baseload generation (e.g., nuclear and gas) and converting it to flexible generation (with a 20% loss). As the VRE share increases further, the non-VRE share decreases and consequently the amount of flexible generation decreases even though nearly all non-VRE generation must be flexible (see section 3.2). As a result, electricity storage as a share of VRE generation declines at large shares. H_2 electrolysis begins to operate after 2070 as technological learning reduces the cost of fuel cells and electrolyzers and large carbon taxes incentivize the deployment of low-carbon flexible generation from hydrogen fuel cells.

3.2 Flexible generation

As described in section 2.3.1, increasing VRE deployment requires that remaining generators become more flexible to manage the variability and intermittency associated with VRE. However, at a VRE share of 50-60%, the amount of flexible generation per unit of VRE generation begins to decline as the non-VRE share of total generation declines. This trend is illustrated in Figure 10 where the flexible share of gross generation declines at a VRE share of 63% in Tax30. At a VRE share up to 38%, flexibility is provided by the flexible operation of hydropower, coal, and gas plants. In Tax30, slightly more flexibility is required for a given VRE share since the carbon tax incentivizes VRE deployment in regions with higher flexibility requirements. In addition, more coal capacity is operated in flexible mode in Tax30 since 38% VRE share is reached in 2030 when there is still significant coal capacity in the system. However, beyond a VRE share of 38%, the carbon tax incentivizes Tax30 to achieve flexibility differently from the baseline.

The baseline scenario continues to rely heavily on gas combined-cycle, gas combustion turbine, and hydroelectric power plants to provide flexibility. Furthermore, as the cost of fuel cells and hydrogen fuel becomes competitive with natural gas, the system phases in decentralized and utility-scale hydrogen fuel cells beginning in 2050 (36% VRE share). In contrast, the carbon tax in Tax30 quickly shifts flexible generation to low-carbon technologies, including hydropower, storage, hydrogen, CSP, and geothermal. By 2100 (83% VRE share), 63% of flexible generation is supplied from storage, 26% from hydropower, 8% from hydrogen, and the remainder from CSP and geothermal. Any inflexible generation from nuclear, hydropower, geothermal, and gas combined-cycle plants is converted to flexible generation through electricity storage so that non-VRE generation becomes almost entirely flexible at 83% VRE share.

[15] Note that 85-100% of electricity storage is used for other purposes in the Old Integration scenario. Here, storage is deployed to manage curtailed electricity from inflexible nuclear baseload plants, essentially transforming inflexible generation to flexible generation.

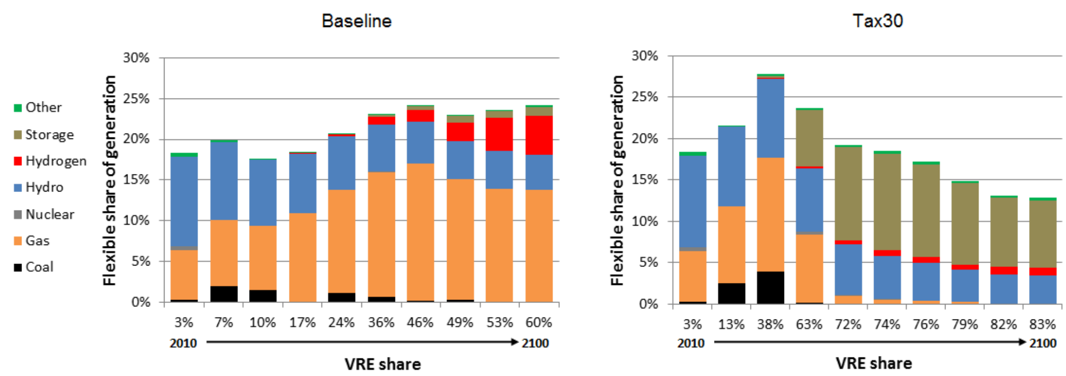

Figure 10: Flexible share of gross generation as a function of VRE share of gross generation before curtailment for Baseline (left) and Tax30 (right) scenarios. VRE shares are those associated with each decade between 2010 and 2100. Other includes geothermal, CSP, biomass, and oil. Values for the Old Integration scenario are provided in Supplementary Figure 7.

3.3 System capacity

The firm capacity requirement described in section 2.2.1 ensures that sufficient firm generating capacity is constructed to meet peak load and contingency events. Conventional generators provide their full nameplate capacity to firm capacity, but the contribution of VRE technologies varies by region and by VRE share. Globally, the firm capacity requirement is about 70% larger than the average annual load. The left side of Figure 11 illustrates the capacity of each generation technology as the VRE share increases and indicates the portion of VRE installed capacity that contributes to firm capacity as the amount below the firm capacity requirement (dotted black line). Most notable is the declining contribution per unit of VRE to firm capacity, which decreases from 16% of installed capacity at a 13% VRE share to 8% of installed capacity at an 83% VRE share. Consequently, as the VRE share increases to 83%, the total installed generating capacity increases dramatically to more than five times the capacity required to meet average annual load (black solid line) and more than three times the firm capacity requirement (dotted black line).

The graphs on the right side of Figure 11 indicate the distribution of technologies that provide firm capacity as the VRE share increases in the Baseline and Tax30 scenarios. The solid black line indicates the average annual load and technologies are sorted so that underutilized technologies (i.e., those that are primarily constructed to provide firm capacity for peaking and contingency events) are above the black line. In the baseline, GHG emissions are not penalized so the electricity system provides peaking capacity almost exclusively with gas combustion turbines. However, even without a carbon tax, firm capacity is supplied increasingly by flexible technologies while baseload generators, such as nuclear and coal, phase out. In Tax30, the carbon tax shifts peaking capacity from gas to utility-scale hydrogen fuel cells in an effort to eliminate CO_2 emissions. Moreover, at 83% VRE share, 97% of non-VRE firm capacity is supplied by flexible, low-carbon generators, including hydropower, storage, hydrogen fuel cells, CSP, and geothermal. The remaining 3% consists of flexible gas combustion turbines (1%) and inflexible nuclear plants operated as baseload (2%). Even in the baseline, only 10% of firm capacity is composed of inflexible baseload generation from coal and gas when the VRE share reaches 60% in 2100. These results suggest that increasing VRE shares will diminish the role of baseload generation in the electricity sector.

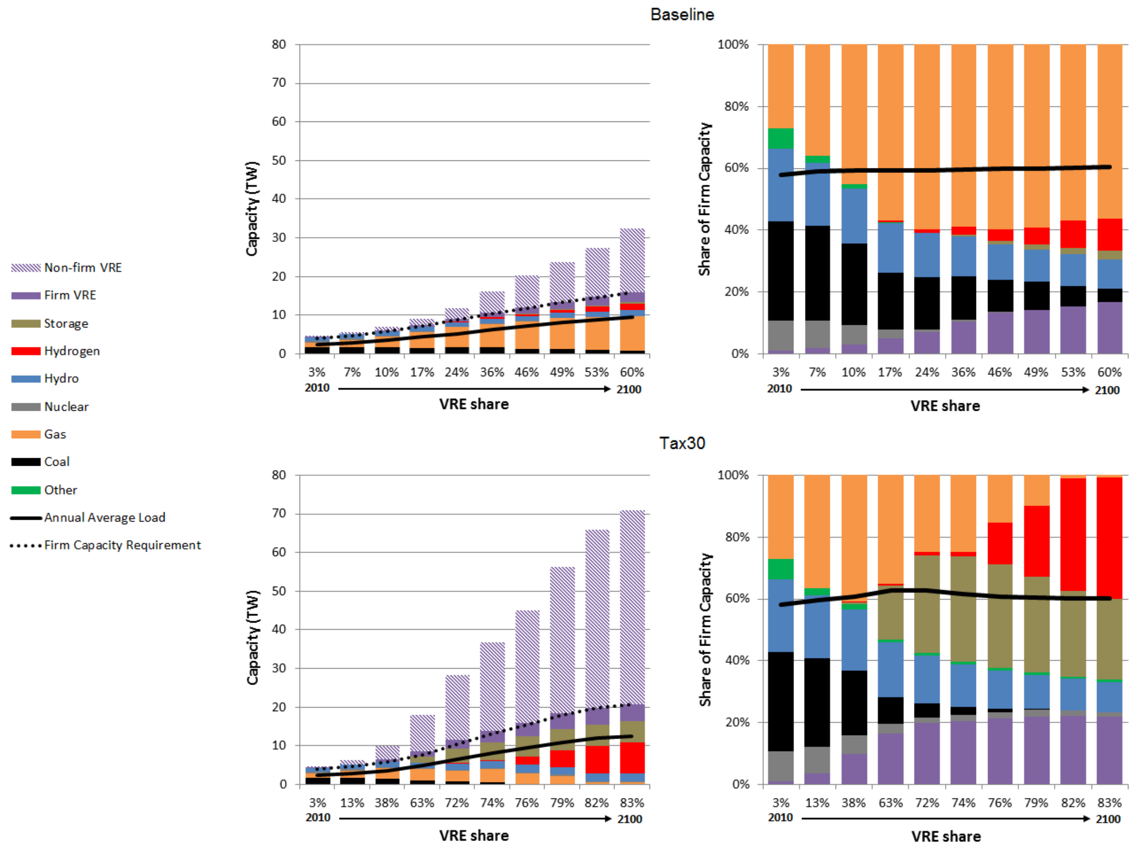

Figure 11: Capacity (TW) and share of firm capacity as a function of VRE share of gross generation before curtailment for the Baseline (top) and Tax30 (bottom) scenarios. VRE shares are those associated with each decade between 2010 and 2100. Other includes geothermal, CSP, biomass, and oil. The solid black line in all figures indicates the annual average load. Values for the Old Integration scenario are provided in Supplementary Figure 8.

3.4 Power Plant Utilization

Without VRE, the system-wide average power plant utilization (i.e., system-wide capacity factor) is dictated by the firm capacity requirement, which demands that firm capacity is ~1.7 times average annual load. This translates to an average system-wide capacity factor of about 55% at 0% VRE share (Figure 12). However, as the VRE share expands, the system-wide average capacity factor converges towards the average capacity factor of VRE, which declines from 33% at small shares to 25% at large shares since lower quality VRE resources must be exploited at large shares. However, the average capacity factor of non-VRE power plants declines to less than 20% at a VRE share of 83%, representing a 65% decline in the average non-VRE capacity factor. This decline occurs despite the fact that many non-VRE generators maintain their theoretical capacity factor at high VRE shares, including hydropower, nuclear, storage, CSP, and geothermal. Thus, the average capacity factor of particular technologies are more heavily impacted than others.

As discussed in section 2, gas and hydrogen-based generators are built to provide peaking capacity and thus would be expected to be most seriously impacted by increasing VRE deployment. The strong impact on the average capacity factor of gas technologies is illustrated in Figure 12 where gas provides peaking capacity up to about 40% VRE share at an average capacity factor of 36-39%. However, above 40% VRE share, the utilization of gas power plants declines and reaches about 2% of installed capacity at a VRE share of 76%, although the total installed capacity of gas power plants also declines during this period (Figure 11). Large carbon taxes shift peaking capacity away from gas and towards utility-scale hydrogen fuel cells in later time periods and this hydrogen capacity also suffers from a very low capacity factor of 2% of installed capacity[16]. Much of the reduced plant utilization can be attributed to VRE deployment and thus supports the finding of Hirth et al. [5] that the reduced utilization of power plants may constitute a large component of VRE integration costs.

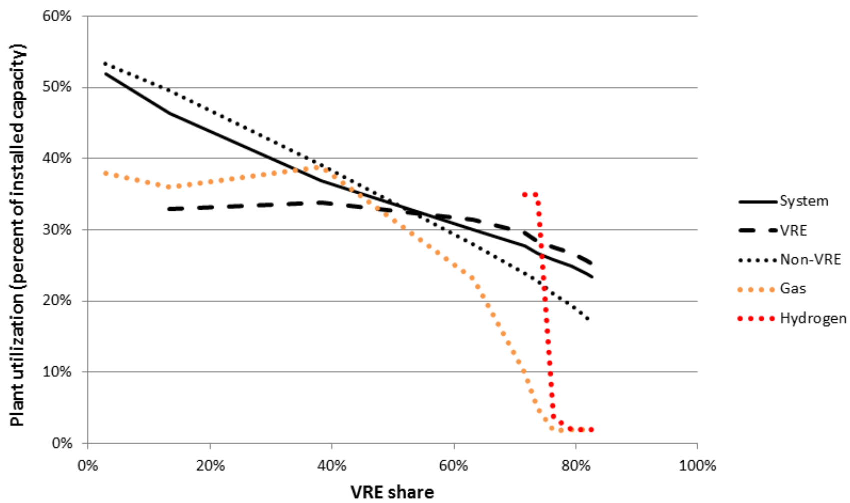

Figure 12: Impact of VRE deployment on power plant utilization in the Tax30 scenario

4 Conclusions

The parameterization of the integration constraints introduced by Sullivan et al. [11] has been improved using regional residual load duration curves (RLDCs), which have enabled a parameterization that is region-specific and more easily reproducible. Specifically, the RLDCs have been used to parameterize the impacts of increasing VRE share on: (1) seasonal and short-term VRE curtailment; (2) non-VRE flexibility; and (3) the capacity value of solar PV and wind capacity. In addition, a flexible mode of operation was added to conventional thermal power plant technologies to account for the additional efficiency, utilization, and cost penalties associated with flexible operation. We find that the updated parameterization is more conducive to the deployment of large VRE shares than the previous

[16] Note that gas CC, gas CT, and utility-scale hydrogen fuel cells are implemented with a minimum generation of 2% of installed capacity so that the model must operate the plants as peakers and cannot build entirely unutilized capacity to meet the firm capacity requirement. This is particularly important since the model would otherwise build unutilized gas capacity even with a carbon tax since the capacity would not produce any emissions if not operated.

parameterization. Two scenarios were evaluated using the updated parameterization, including a baseline scenario with no climate policy and a climate policy scenario in which a \$30/ton CO_2 carbon tax is introduced in the 2021-2030 period and increases 5% annually thereafter. These scenarios are used to explore how the operation and structure of the electricity system changes as the VRE share increases with and without climate policy and to assess whether the reduced form representation of VRE integration impacts produces plausible system developments. We find that the updated representation can reproduce the following stylized facts regarding the impact of VRE deployment on the electricity system.

1. *The average capacity factor of non-VRE power plant capacity declines when the VRE share increases.*

As the share of VRE increases, the firm capacity requirement remains constant, but the utilization of this capacity declines as more generation is supplied by VRE. In the Tax30 scenario, the average utilization of non-VRE power plant capacity declines by 65% when the VRE share increases from 0% to 80% of gross generation. The reduction in utilization is even more pronounced for technologies that are used for peak generation, including utility-scale hydrogen fuel cells and gas power plants, which have a capacity factor of 2% of installed capacity at VRE shares above 70% of gross generation. This reduced utilization will undoubtedly increase the costs associated with integrating large shares of VRE.

2. *Inflexible baseload generation is incompatible with large VRE shares*

As the VRE share increases, the remaining portion of generation supplied by non-VRE must become increasingly flexible to manage the variability and uncertainty associated with VRE generation. As a result, inflexible baseload generation (e.g., nuclear) is phased out and the model begins to rely almost exclusively on flexible generation from storage, hydrogen, gas combustion turbines, and hydropower. Some inflexible generation does remain in the system, including nuclear, but the system uses electricity storage to improve the flexibility of the overall system.

3. *Electricity storage and hydrogen technologies are crucial for integrating large shares of VRE (>50%)*

Both electricity storage and hydrogen technologies play a critical role in integrating VRE when shares exceed 50%. Electricity storage is used not only to store the excess VRE generation that would otherwise be curtailed, but is also the primary technology for providing system flexibility in the carbon tax scenario. Storage provides system flexibility by storing inflexible generation and converting it to flexible generation, although with a 20% energy penalty. Similarly, hydrogen technologies are used both for absorbing VRE curtailment (electrolysis) and for providing system flexibility and firm capacity (utility-scale fuel cells). These technologies are deployed in later time periods when technological learning leads to a reduction in the cost of H_2 electrolyzers and fuel cells. In the baseline scenario, H_2 fuel cells are primarily used to provide system flexibility as they become competitive with gas combustion turbines. In contrast, H_2 fuel cells are used in the carbon tax scenario to provide low-carbon peak generation and firm capacity.

Although the reduced form representation of VRE integration in MESSAGE provides plausible electricity system adaptations, there are several aspects that could be improved. First, research on the flexible operation of thermal power plants (e.g., coal and nuclear) is quite new and more information is needed to better parameterize the degree to which thermal power plants can be cycled and the cost, efficiency, and utilization penalties associated with flexible operation. Second, the RLDCs used for the parameterization are based on current regional load curves. In reality, these load curves will evolve over time and could have significant impacts on the parameterization of VRE capacity values, flexibility requirements, and VRE curtailment. However, projecting regional load curves over the next century is a daunting task and, thus, current load curves will likely remain the best option for the near future. Third, given the importance of electricity storage and the fact that MESSAGE includes only a generic storage technology with unlimited potential, additional work is needed to introduce specific storage technologies (e.g., pumped hydropower, compressed air) to better represent the costs and limited potentials associated with these technologies. Fourth, additional research is needed to assess whether hydrogen fuel cells can provide the flexibility exhibited in the model and to fully account for the cycling costs associated with operating them flexibly. Furthermore, the version of MESSAGE used for these scenarios does not include hydrogen fuel cell vehicles. The inclusion of this technology could provide a larger market for hydrogen that could allow for an even larger role for hydrogen in managing VRE. Fifth, this study does not consider the integration benefits of demand response options, which may provide opportunities to manage supply fluctuations from the demand side. Thus, demand response options should be implemented and explored in the model. Finally, it would be useful to compare the results of MESSAGE with those from a detailed power system model with high temporal resolution to validate how well MESSAGE simulates the impacts of VRE deployment.

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