Demand Response for Ancillary Services

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***Abstract*—.Many demand response resources are technically capable of providing ancillary services. In some cases, they can provide superior response to generators, as the curtailment of load is typically much faster than ramping thermal and hydropower plants. Analysis and quantification of demand response resources providing ancillary services is necessary to understand the resources' economic value and impact on the power system. Methodologies used to study grid integration of variable generation can be adapted to the study of demand response. In the present work, we describe and implement a methodology to construct detailed temporal and spatial representations of demand response resources and to incorporate those resources into power system models. In addition, the paper outlines ways to evaluate barriers to implementation. We demonstrate how the combination of these three analyses can be used to assess economic value of the realizable potential of demand response for ancillary services.**

Index Terms—***Author, please supply index terms/keywords for your paper. To download the IEEE Taxonomy go to http://www.ieee.org/documents/2009Taxonomy_v101.pdf.***

I. Introduction

CONTROLLABLE customer loads represent a significant and largely untapped resource for supplying reliability services to the electric power system. Load participation in grid reliability, by providing ancillary services (AS), has a number of benefits. It deepens the pool of reliability resources available to system operators; increases system flexibility to manage variability and uncertainty, which increases with variable generation (VG) like wind and solar generation; enables retail customers to manage costs; and enhances system efficiency. While loads can technically be used for AS, implementation challenges must be addressed before loads can be routinely deployed alongside conventional supply-side resources in all regions. Thus, there is a gap between the technical and realizable potential of loads to provide AS.

A number of studies have examined the potential of loads to provide AS, but these have been either conceptual [1] or address specific loads [2]. The bulk of the literature focuses on traditional demand response (DR) for emergency load relief and peak load management [3], [4] or price responsive demand [5]. There are key differences between these applications and DR for AS. For AS, technical requirements are more challenging in terms of speed and accuracy; and the energy component is small relative to capacity. Furthermore, AS are needed year-round and not just during peak hours.

The power system must balance generation and load, and most balancing occurs through the energy market. However, at the shortest time scales, additional mechanisms regulate supply-demand balance and respond to contingencies like the sudden loss of a large generator or major transmission line [6]. These are termed AS to distinguish them from energy products. AS do involve small amounts of energy, but their real value is in the capacity held in reserve and the technical capability to respond reliably and quickly to maintain balance. Although AS include both real and reactive power applications [7], this paper focuses only on real power AS. These include 1) regulation reserve, which responds moment-by-moment to maintain area control error; 2) contingency reserve (both spinning and non-spinning reserve), which responds to sudden but infrequent disruptions; and 3) recently proposed flexibility reserve which responds to large and unexpected wind and solar ramp events [8], [9].

AS requirements vary by region, limiting the possible scale of DR deployment. For large interconnected systems with sub-hourly markets, regulation requirements are around 1% of load [10]. In small systems or those with less granular hourly markets, requirements can be larger. The introduction of wind and solar generation may increase the need for regulation due to greater intra-hour variability. Unlike regulation, the need for contingency reserve is not strongly linked to VG penetration [11]. The requirement is based on the largest credible contingency in the balancing authority area (BAA) and approximate to between 5%–7% of load, of which half is sometimes required to be spinning. In addition to current AS, the requirement for flexibility reserves varies with the likelihood of large un-forecasted ramps in the net profile of load and VG [12].

Methodologies used to study large-scale grid integration of VG can be adapted to assess the value of DR for AS [13]. A primary requirement is the use of power system models, which simulate grid operations and co-optimize the provision of energy and AS. Accurate simulations require extensive data sets including detailed time- and location-dependent resource information and can evaluate the ability of DR to help manage increased variability and uncertainty [14].

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TABLE I
SELECTED ANCILLARY SERVICE TARIFFS AND REQUIREMENTS† ACROSS THE U.S.

Control Area	Tariff $/kW-month (Requirement %)			
	Regulation		Spinning	
AEP West Zone	2.64	(1.20%)	3.56	(2.10%)
AZ Public Service	7.41	(1.17%)	6.26	(3.19%)
Duke Energy CP&L	3.96	(1.20%)	3.96	(1.77%)
El Paso Electric	3.10	(0.87%)	3.10	(1.75%)
FL Power & LIght	4.82	(1.35%)	5.16	(0.43%)
Idaho Power	6.53	(1.50%)	6.53	(2.86%)
PacifiCorp West	7.80	(4.24%)	8.80	(1.75%)
Portland Gas & Elec.	6.70	(1.30%)	6.45	(3.50%/2.50%)
Pub. Serv. Co. of CO	6.74	(1.50%)	6.88	(3.50%/2.50%)
Pub. Serv. Co. of NM	8.60	(1.50%)	9.36	(3.50%)
Puget Sound	5.50	(2.00%)	6.68	(3.13%)
Southern Co.	4.20	(1.15%)	4.20	(2.00%)
Tuscon Electric	12.1	(1.29%)	12.09	(3.50%)

†Requirements in WECC are a percentage of the transmission customer's contribution to the coincident system peak and can be defined separately for the fraction of load served by thermal plants and hydropower plants.

The present work outlines an approach to assess the realizable potential of DR for AS, in terms of economic value and implementation challenges. Section II gives an overview of current AS markets. Section III provides details of the study methodology. The starting point is an estimate of the technical potential based on an inventory of end-use loads, their availability, and potential flexibility, both individually and in aggregate, to provide AS. The value of AS at low and high penetration levels of VG is calculated through the use of power system modeling. Section IV discusses the barriers to implementation. These barrier assessments indicate who can currently participate and how much value they can capture. Section V reports on results, and Section VI discusses key issues and paths forward.

II. ANCILLARY SERVICE MARKETS

The value of AS depends on rates and procurement mechanisms, which vary regionally and annually. AS tariffs are settled through the regulatory process, and transmission providers (TP) procure AS on behalf of its transmission customers (TC), either as a cost-based service or through third-party supply. Where there are organized wholesale markets, an Independent System Operator or Regional Transmission Organization (ISO/RTO) runs a competitive market for AS. Despite regional variations, most entities share common design elements.

In regions without organized wholesale markets, transparent AS prices are unavailable but may be inferred from tariffs filed by TPs. Tariffs are based on the TP's expected annual cost of providing AS, adjusted for prior year under- or over-collection and represent the most that the TP can charge for AS. AS are typically quoted on a monthly basis; and costs are generally allocated to TC according to their contribution to the transmission system coincident peak load. For illustration, a few AS tariffs are given in Table I. However, utilities may self-supply AS rather than purchase them from the TP. So, quoted tariffs may yield limited insight into AS value.

In regions with organized wholesale markets, transparent AS prices are available and include two components, an availability bid and an opportunity cost. AS providers recover their marginal costs, such as increased wear-and-tear and higher fuel consumption due to degraded heat rates, through the availability bid. If

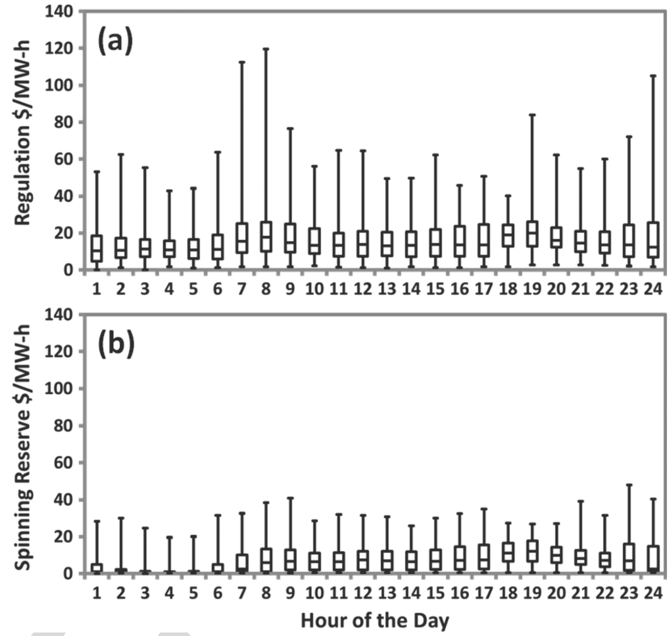

Fig. 1. Regulation and spinning reserve prices in the California ISO market. For the historical year 2011, maximum, third quartile, median, first quartile, and minimum prices are shown for each hour of the day. (a) Regulation prices are high throughout all hours of the day, whereas (b) spinning reserve prices tend to follow the system load.

providers forego an energy sale to provide AS, they are entitled to a lost opportunity cost, equal to the difference between the energy market clearing price and their energy market bid. Typically, the AS market clearing price equals the sum of the availability bid and opportunity cost for the marginal unit [15]. In contrast with regions lacking organized wholesale markets, rates paid for AS vary by hour (or shorter) and display strong daily and seasonal variations, as shown in Fig. 1.

Since there is limited DR for AS provided commercially in most regions, the potential revenue a DR provider could earn is not fully known [16]. However, AS tariffs and historical ISO/RTO market prices establish a starting point for estimating the revenue a DR provider could earn if it is allowed to supply AS. DR program payments are comparable to AS rates on a dollar per unit of reserved capacity basis ($/kW); but differ on the basis of curtailed energy ($/kWh). Though AS are deployed more frequently than traditional load shedding events, the annual hours of curtailment are much less; and individual events are much shorter. Emergency and economic load shedding programs are usually limited to 10–15 calls per year, each lasting 4–8 hours [17]. In contrast, contingency reserves are deployed as often as every couple days or as seldom as every couple weeks, but the average duration is 10 minutes and rarely longer than 30 [18]. Thus, AS programs may appeal to retail customers and end-use loads that find frequent and short curtailments more acceptable than infrequent and long ones.

III. METHODOLOGY

This section describes a methodology for quantifying DR and implementing it into power system models under different penetrations levels of VG. DR is capable of performing various functions for the power system. For these functions, uniform product definitions do not exist across all regions, so we assume

TABLE II
GENERALIZED PRODUCT DEFINITIONS FOR LOAD PARTICIPATION IN ANCILLARY SERVICES, ENERGY, AND CAPACITY MARKETS

		Physical Requirements			
Product Type	General description	How fast to respond	Length of response	Time to fully respond	How often called
Regulation	Response to random unscheduled deviations in scheduled net load	30 seconds	Energy neutral in 15 minutes	5 minutes	Continuous within the specified bid period
Contingency	Rapid and immediate response to a loss in supply	1 minute	$\leq$ 30 minutes	$\leq$ 10 minutes	$\leq$ Once per day
Flexibility	Additional load following reserve for large unforecasted wind/solar ramps	5 minutes	1 hour	20 minutes	Continuous within the specified bid period
Energy	Shed or shift energy consumption over time	5 minutes	$\geq$ 1 hour	10 minutes	1-2 times per day with 4-8 hour ahead notification
Capacity	Ability to serve as an alternative to generation	Top 20 hours coincident with balancing authority area system peak			

five prototypes that are broadly representative of current market structures, described in Table II. In addition to AS; we include the potential for DR to participate in energy and capacity markets; however, in this work, we focus exclusively on AS. The five products are distinguished by their physical requirements which include: 1) how fast the resource must respond; 2) the length of the response; 3) the time to fully respond; and 4) how often the product is called. The product definitions combined with details on specific end-use loads determine DR resources, which are then input to the power system simulations. Our analysis focuses on BAAs within U.S. portions of the Western Interconnection (WI).

A. Assessment of Load Capabilities

The ability for DR to provide AS depends on the flexibility of the underlying loads, their availability, and the aggregation scheme. Flexibility is a function of the load's operating characteristics and constraints. The availability of DR can correlate with the season and weather; and concentrations of industries, facility types, and customer usage patterns vary regionally. The performance of the aggregate resource, particularly for smaller loads, can be more important to the power system than that of each individual load. For example, multiple small loads may receive the same spinning reserve response command. The aggregate response could be predictable and reliable even if that of any individual load is not [13]. Alternatively, aggregation can create regulation from a portfolio of loads that are individually incapable of such. In many cases, flexible loads have storage components that augment their ability to be dispatched when needed. Storage may be thermal (e.g., building heating and cooling inertia, hot water tanks, and cold storage) or product (e.g., stockpiling manufactured or process products or water for irrigation and wastewater treatment) [1].

Quantifying the DR resource potential starts with developing load profiles across the commercial, residential, and industrial sectors for each BAA. The DR capability is then defined as a fraction of the load profile that can provide each of the five products (Table II). Across end-uses, a set of flexibility criteria filter load profiles into subsets capable of responding to DR dispatch instructions. The filters have three components: sheddable (S), controllable (C), and acceptable (A). Sheddability relates to physical constraints of the end-use equipment, and controllability relates to the presence of suitable control systems at facilities. Acceptability relates to user attributes like building occupant comfort and employee work schedules. This fraction is difficult to assess. As we are quantifying future capabilities of electricity consumers to participate in DR products that are either currently nonexistent or have limited participation, we have made assumptions using DR participation data, goals and planning documents collected from public discussions in various service territories, limited pilots of AS, and consultations with facility managers.

Fig. 2 illustrates how the filters are applied to commercial lighting to provide regulation [19]. Field tests have shown that for some types of commercial buildings, temporary sheds of 25%–33% are possible without compromising mission critical functions [20]. Weighted by commercial building type, we project, for the 2020 study year, an aggregate 18% penetration of energy management and control systems and dimmable ballasts [21]. In the case of buildings, we assume that acceptability is negatively correlated with occupancy, which we infer from lighting load in commercial buildings (and water heating load in residential buildings).

Within a given BAA and end-use type or industrial subsector, sheddability is assumed to be evenly distributed. However, acceptability and controllability are assumed to be coincident: loads with the control capabilities to participate in AS are assumed to be the most willing to participate, and vice versa. Therefore, the total flexibility (F) is time-dependent and specific to each type of load (l) and each type of product (p) such that:

$$F_{l,p}(t) = S_{l,p}(t) \cdot \min[C_{l,p}(t), A_{l,p}(t)]. \tag{1}$$

Consequently, the total DR resource (R) potential is:

$$R_{l,p}(t) = F_{l,p}(t) \cdot L_l(t) \tag{2}$$

where (L) is the load profile. Only responses which are both controllable and acceptable can participate (taking the smaller value at each hour), and these participating loads can respond up to their sheddable value.

A significant challenge with this approach stems from the limited availability of disaggregated hourly load data. Here, we develop notional hourly load profiles from various data sources,

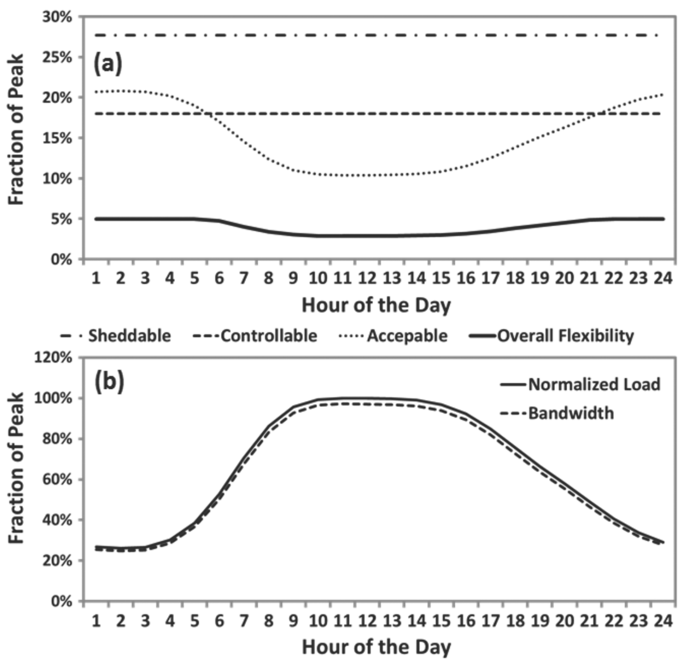

Fig. 2. Flexibility calculation for regulation reserve applied to commercial building lighting loads for an example 24 hour period: (a) the overall flexibility as a function of the three flexibility filters (sheddable, controllable, and acceptable) in accordance with (1) and (b) the fraction of the commercial lighting that can provide regulation reserves.

end-use specific load models, and related input assumptions. Loads are divided into two groups that require different approaches. These two groups have different driving factors, and the derivations of hourly load profiles are described separately in the next two subsections.

1) Building, Agricultural, Municipal, Refrigerated Warehouse and Data Center Loads: A diverse set of end-uses are represented in this assessment, given in Table III. Building DR includes loads attributable to space conditioning, water heating, and lighting. Agricultural DR includes loads attributable to crop irrigation. Municipal DR includes loads attributable to fresh water pumping, waste water pumping, and outdoor lighting. Lastly, we also considered loads attributable to warehouse refrigeration and data center servers and equipment cooling. To model load behavior, the resource assessment incorporates each load's dependence on weather, business-type, and local population as well as historical data, when available.

The load profiles are assembled through a combination of top-down and bottom-up approaches. Census data allows for modeling population-dependent loads such as municipal water pumping. Federal Energy Regulatory Commission Form 714 data provides hourly loads aggregated at the BAA-level [22]. Energy Information Administration (EIA) Electric Power Annual data [23] provides a decomposed view at the BAA-level of consumption data for many economic sectors. EIA survey data including the Residential Energy Consumption Survey [24] and Commercial Building Energy Consumption Survey [25] also provide disaggregated consumption for various end-uses. Load profiles for agricultural irrigation depends on crops grown and planting and harvest dates and is derived from Department of Agriculture Farm and Ranch Irrigation Survey data [26].

TABLE III
END-USE LOADS AND PROCESSES INCLUDED IN THE DEMAND RESPONSE RESOURCE ASSESSMENT

Buildings and Other Loads		Industrial Processes by SIC Codes	
Commercial	Space heating	Food Products	2011, 2015,
	Space cooling		2024, 2037
	Lighting	Textile Mill Products	2211
	Ventilation	Lumber/Wood Prod.	2421
Residential	Space heating	Paper Products	2611
	Space cooling	Chemical Products	2812, 2813,
	Water heating		2816, 2819,
Municipal	Fresh water		2821, 2822,
	pumping	Petroleum Refining	2911
	Waste water	Stone, Clay, Glass,	3211, 3221
	pumping	and Concrete	3241
	Outdoor lighting	Primary Metals	3321, 3325,
Agricultural	Crop irrigation		3334, 3339,
	pumping		3341, 3354,
Data centers	Servers and		3356, 3363
	equipment		3364, 3365,
	cooling		3366, 3399
Warehouse	Refrigeration	Transportation Equip.	3713

The most detailed data is available for California (CA), such as through the Commercial End-Use Survey [27] and from the CA ISO. In the absence of detailed end-use load data outside of CA, we applied the end-use data available in CA to other parts of the WI by fitting the detailed CA data to coarse energy predictions for the other WI BAAs. The data was additionally extrapolated to account for differences in weather patterns between CA and the other states. Within CA data, a correlation was seen between the average daily temperature variability $(T_{\max} - T_{\min})$ and the load variability $(L_{\max} - L_{\min})$, as a percent of average load. This correlation was modeled using a linear regression. For each non-CA BAA, the most similar CA BAA was selected based on seasonal energy consumption patterns and the corresponding CA BAA regression equation was used to estimate the load variability in each month for the non-CA BAA. The CA BAA load curve was then scaled and offset to match both the predicted monthly energy consumption and the predicted daily load variability.

2) Industrial Process Loads: The industrial sector is highly heterogeneous, with manufacturing processes represented by over 600 manufacturing codes within the four digit Standard Industrial Classification (SIC) system. In order to prioritize the top industries for DR, we examined the total annual electricity consumption and average power demand per establishment as well as relied upon field experience. The prioritization led to 36 SIC codes of which 30 are represented in U.S. portions of the WI (Table III).

The load profiles are developed through analysis of each manufacturing process. Manufacturing processes are composed of process steps that reflect stages within the process flow. Within a process step, devices fall into several categorizations from smooth, continuous operation such as electrolysis and induction heating; to lightly modulated operation such as fluid movement using pumps, fans, and blowers; and to heavily modulated operation such as cutting, pressing, separation, and electric arc heating [28]. Device-level loads are aggregated to the plant-level by scaling each load profile by its contribution to the total

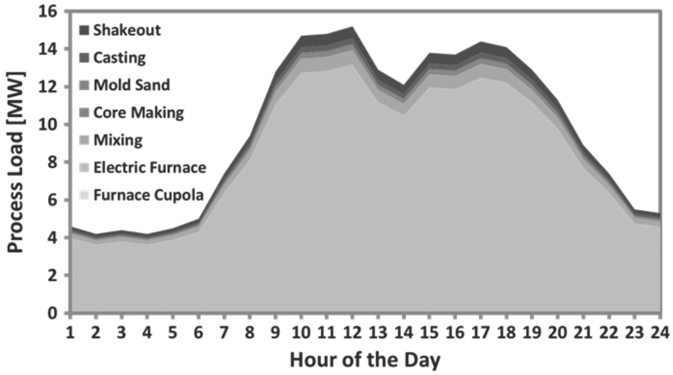

Fig. 3. Example load profile for Gray and Ductile Iron Foundries (SIC 3321), disaggregated by major process steps over a 24 hour period.

plant load and subsequently combining them [29]. Fig. 3 provides one specific example for Gray and Ductile Iron Foundries (SIC 3321).

Total annual electricity consumption for individual plants provides an overall scaling factor for the hourly loads and is estimated using two data sources. The U.S. Industrial Manufacturers Database from Manufacturer's News Inc., (MNI) houses information on 375 000 manufacturing facilities including mailing addresses, SIC codes, and estimated annual sales volumes [30]. The Industrial Assessment Center (IAC) database contains over 15 000 U.S. Department of Energy assessments at specific facilities across the U.S.; including information on annual sales, annual energy consumption by fuel type, facility square footage, number of employees, and energy savings projects [31]. Using the IAC data, we perform a regression on electricity consumption as a function of sales volume, see Fig. 4(a) [32]. The resulting fit is then applied to plants in the MNI database. Fig. 4(b) provides a state-by-state comparison to EIA Electric Power Annual data [23].

B. Power System Modeling

The value of DR providing AS can be estimated using power system models that capture optimal economic operation through security constrained unit commitment (UC) and security constrained economic dispatch (ED) processes. Referred to as production cost models, they help plan system expansion, evaluate aspects of reliability and market efficiency, and estimate fuel costs and emissions. The models simulate operation of the generator fleet to minimize the total production costs while maintaining adequate reserves to meet contingency events and regulation requirements. Modern production cost models often include DC optimal power flow simulations to ensure basic transmission adequacy.

UC/ED models co-optimize energy and AS, and therefore can be used to calculate the opportunity cost and heat rate impacts associated with operating thermal power plants to provide reserves. When generators withhold some of their capacity to provide AS, there is a fuel consumption penalty due to the less optimal operating point and also non steady-state operation in the case of regulation. In addition, more units may need to be committed and online, leading to increased startup and shutdown costs. Since generators have minimum operating limits, holding

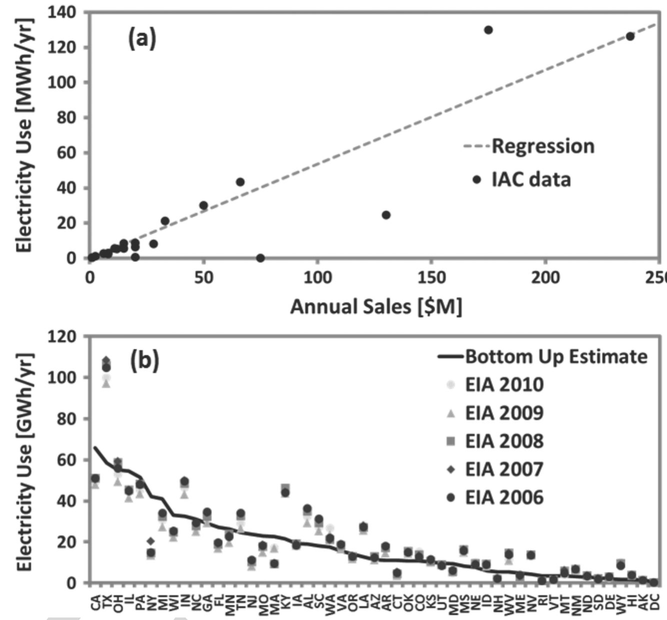

Fig. 4. (a) Statistical regression on Industrial Assessment Center case studies for glass making (SIC 3211). (b) Comparison of bottom up estimates of electricity consumption compared with state level data from the Energy Information Administration. The data is rank-ordered according to the bottom up estimates, and a line is added as a guide to the eye.

AS may also lead to less efficient, higher marginal costs units, providing energy.

Our analysis uses the commercial software PLEXOS (in deterministic mode) to model multi-stage UC and ED processes. The model begins with a mid-term model that decomposes long-term constraints, such as annual energy limitations on hydro generation and DR dispatch, into daily constraints. This data is passed to the day-ahead UC model which schedules resources hourly in 24-hour windows with an additional twenty-four hour look ahead period. Those decisions are then passed to the ED model which dispatches resources in 5-minute intervals. We linearly interpolate the hourly DR profiles to 5 minutes. As typical with UC/ED models, the model can calculate the cost of holding reserves, but regulation dispatch and contingency events are not simulated (though suitable multi-timescale models are starting to appear [33]).

The costs of AS are sensitive to constraints on generators. The model uses parameters like ramp rates and operating limits to determine a generator's ability to provide AS plus follow energy dispatch instructions. However, only a subset of generators is equipped (or has turned on) automatic generation control (AGC) to provide regulation. Thus, we assume that 60% of all generating capacity can provide regulation and flexibility reserve. We also impose that nuclear, biomass, and geothermal units do not provide any AS and further constrain combustion turbines from providing regulation [34].

The modeled scenarios are based on the 2020 case established by the Transmission Expansion Planning Policy Committee (TEPPC). Load patterns use 2006 data scaled to include projected growth, and wind and solar data are from 2006. A base case includes currently planned renewable capacity additions, and a high renewable energy case includes 24% energy from wind generation and 5% from solar generation across the

WI. AS requirements vary hourly, based on statistical analysis of wind and solar resource data and short-term forecasts [35].

IV. Assessment of Barriers to Implementation

In addition to technical issues, implementation barriers impact the DR potential by creating requirements that increase the cost of supplying AS, decrease the revenue potential for providers, limit enrollment of retail customers, or outright forbid loads from providing certain products. Traditionally, AS have been provided exclusively by generators. As such, AS procurement mechanisms may be specific to the physical characteristics of generators, rather than the essential qualities necessary to perform AS functions.

Market and policy barriers for DR fall into several categories. Barriers associated with bulk power system product definitions relate to how regional reliability councils and BAAs choose to define AS, explicitly including or excluding certain classes of resources. If a DR resource fits within the bulk power system's definitions, BAA rules to define the attributes of performance (e.g., minimum resource size) and the required enabling infrastructure (e.g., telemetry) for these services may hinder program providers from participating effectively in AS markets. In addition, available revenues from being an AS provider must be sufficient and able to be captured with enough certainty to meet return on investment levels for fixed and variable enabling infrastructure investment costs. Lastly, the regulatory compact between utility and regulator, along with other statutes and decisions by state policymakers (e.g., excluding non-utility program providers), may also create barriers that program providers must overcome in order to pursue DR as an AS providers.

Addressing these barriers requires engaging the entity that created the barrier who may not be inclined to make needed changes. Such efforts introduce additional costs, both in time and financial resources, in implementing solutions. For instance, ISO/RTOs attempting to change their product definitions, must first initiate internal and external stakeholder processes that require among others, overcoming preconceptions about the capabilities of particular resources. They must then seek approval from federal regulators before any changes may be made to operating practices and also contend with both financial and human capital resource constraints.

Retail and wholesale market environments significantly influence barriers. DR programs seek to earn a return on their upfront investment through market sales or cost savings resulting from program implementation, but investment returns may be limited. For example, in Texas, contractual arrangements between competitive retail electricity providers and customers have short time frames, spanning from 1 to 24 months, increasing the difficultly and risk of generating sufficient revenue to offset the cost of enrolling and enabling each customer. Conversely, entities could offer favorable electricity rates or incentives through DR programs as a way to improve customer retention or recruitment. In states with a vertically integrated electric utility retail structure like Wisconsin, which is within a wholesale market environment, but also in Colorado, where no such market exists; utilities could profit through increases in off-system sales. Their generation assets could supply energy rather than holding

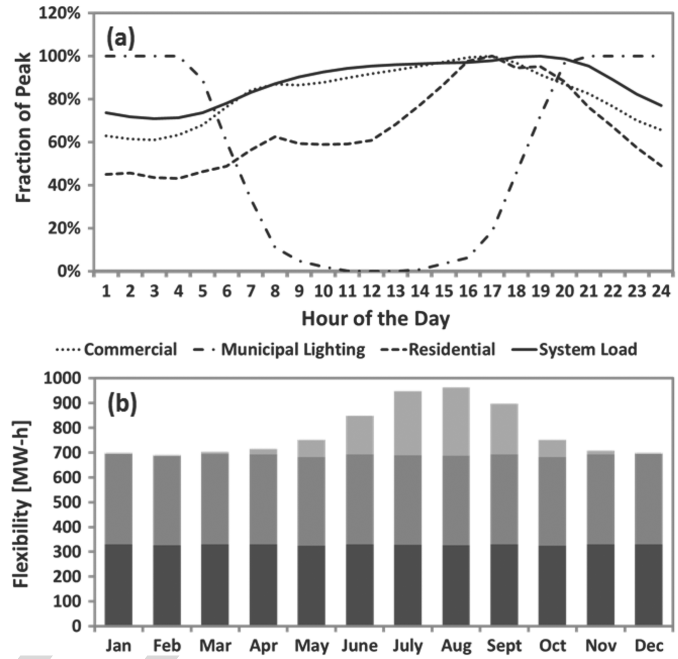

Fig. 5. (a) Average hourly availability of flexibility reserves from residential, commercial, and municipal load across U.S. regions of the Western Interconnect. Each resource class has been normalized to its peak. (b) Hourly availabilities for flexibility reserve in commercial buildings, averaged for each month of the year, show the level of seasonal variation.

capacity for AS; however, the utilities are allowed to retain only a fraction of any resulting profits.

V. Results

DR resource data was collected for areas within the WI. The dataset includes 13 types of commercial, residential, agricultural, municipal loads, data center and refrigerated warehouse loads, and 30 industrial processes. These loads were further disaggregated into 33 BAAs in the western U.S., and the DR availability was calculated for each of the five products and for each hour of the year. The selected end uses reflect approximately 42% of residential electricity use, 66% of commercial electricity use, and 27% of industrial process electricity use.

The DR resource characteristics vary considerably among economic sectors and end-uses. Loads like agricultural crop irrigation and equipment cooling at data centers exhibit fairly flat hourly profiles, while others like commercial buildings have higher availabilities during peak hours and weekdays. As shown in Fig. 5(a), most building loads have significant variation over the hours of the day; however, some like commercial ventilation and lighting are fairly consistent month-to-month [Fig. 5(b)]. Ventilation in commercial buildings is needed both during heating and cooling seasons, and its availability is similar throughout the year.

Based on the realizable potential, we implemented DR in a test system based on the Rocky Mountain Power Pool (RMPP). The RMPP consists of the Public Service of Colorado (PSCO) and Western Administration of Colorado and Missouri (WACM) BAAs. There are four cases, summarized in Table IV, at two penetration levels of wind and solar PV generation with and without DR. For the DR cases, we simulated the commercial, residential, agricultural, data center, and municipal

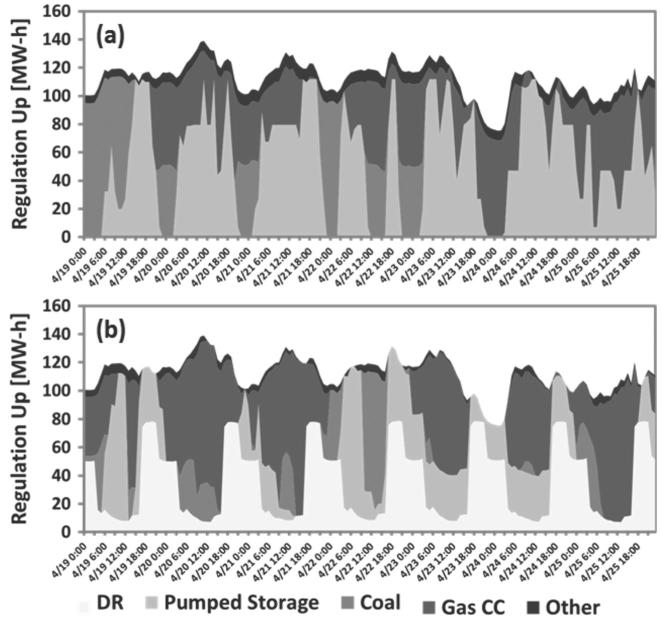

Fig. 6. Example output of the power system simulation showing the holding of regulation reserve in the day-ahead market for different resource types in the low RE case with 8% wind and 3% solar generation (a) and the low RE case with the availability of demand response (b). The time series covers a single week in April for the study year 2020.

DR resources listed on the lefthand column of Table III. We find, under possibly conservative estimates of acceptability, the size of the DR resource for AS is comparable to the requirement. For instance, Table IV shows that in Case 2, 44% of the regulation requirement was met by DR, representing 96% deployment of the available DR resource capable of providing regulation. Fig. 6 shows example outputs representing one week in April for the holding of regulation reserve by different supply types. Marginal cost duration curves for the three AS and for each of the four cases is given in Fig. 7. It shows the extent to which DR resources, as zero cost bid participants, tend to suppress prices, which illustrates one important aspect of economic value assessment of DR. Simulations under varying compositions of grid assets are necessary to draw conclusions from model outcomes.

VI. Discussion

Characterizing the DR resource for AS and developing a framework to translate its technical potential into a realizable potential provide essential information that can guide planners to understand the scale of the DR resource, developers to target the most technically and economically viable opportunities, regulators to understand how their decisions change the resource availability, market designers to construct alternative pricing mechanisms (and market monitors to verify marginal costs and opportunity costs); and technology innovators to focus on high leverage research and development needs.

Currently, DR resources are only minor players in most AS offerings, with ERCOT contingency reserves being a notable exception [36]. To identify the conditions necessary to enable this potential resource, an evaluation of today's economic and regulatory barriers and ways to address these barriers are required. In some cases, regulations and rules have not evolved

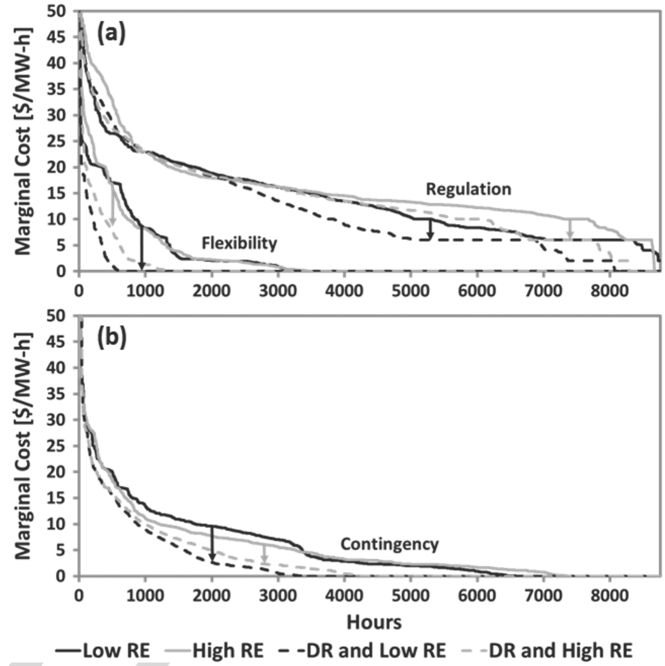

Fig. 7. Marginal cost duration curves for day-ahead regulation up and flexibility prices in the Rocky Mountain Power Pool (a) and spinning reserve prices in the Public Service of Colorado Balancing Authority Area (b). The black lines refer to cases with 8% wind and 3% solar generation, and the grey lines refer to cases with 24% wind and 5% solar generation. These cases are compared to those with deployment of demand response resources (dashed lines). The arrows show price suppression due to demand response providing AS.

TABLE IV
Characteristics of the Four Study Cases

	% Wind/ Solar PV	% Reserves[†] held by DR (% Availability)[‡] Reg. Up		Flexibility		Contingency	
Case 1	8%/3%	-	-	-	-	-	-
PSCO						-	-
WACM						-	-
Case 2	8%/3%	44%	(96%)	71%	(65%)	14%	(78%)
PSCO						20%	(79%)
WACM						6%	(72%)
Case 3	24%/5%	-	-	-	-	-	-
PSCO						-	-
WACM						-	-
Case 4	24%/5%	32%	(94%)	52%	(87%)	12%	(66%)
PSCO						17%	(68%)
WACM						5%	(62%)

[†]Regulation and flexibility reserve are assumed to be shared in the PSCO and WACM balancing areas but spinning reserve is held separately.
[‡]Percent availability is the DR held for an AS as a fraction of the total availability of DR for that AS; which, in these simulations, exclude industrial process loads.

and adapted to accept new technologies like DR for AS; and in others, there exist conflicting priorities such as concerns of fairness to incumbent technologies and consumer protection.

Many ISO/RTOs are finding ways to alter the AS product requirements such that the quality of the service they are procuring is maintained but the pool of resources that can provide it is expanded to include DR. Advancements in technology through research and development efforts and increased market adoption can jointly help bring down the cost of automation and control technologies and communications infrastructure, making participation more cost effective. Increases in benefits, through market rule changes (e.g., scarcity pricing, reserve demand curves) can likewise contribute to an increase in the cost effective procurement of AS from DR. Finally, regulators and other policymakers can address business model concerns through changes in the regulatory compact.

The presented work reflects an initial effort to explore DR for AS. Subsequent modeling and analysis efforts will include greater disaggregation of critical and sensitive DR resources by load type; by time of year, day, and hour; and by location. Also, the increasing availability of smart metering data may help improve load modeling. Probability-weighted simulations based on the likelihood of various loads and deployment of smart grid functionality for future years will also be explored to assess DR for various national-scale energy outlooks, and for a range of VG penetration levels.

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