Energy Policy 109 (2017) 601–608

Contents lists available at ScienceDirect

Energy Policy

journal homepage: www.elsevier.com/locate/enpol

# Emissions implications of downscaled electricity generation scenarios for the western United States

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ARTICLE INFO

*Keywords:*
Electricity dispatch
Air quality
Emissions fees
Nitrogen oxides
Natural gas
Renewable energy

ABSTRACT

This study explores how emissions from electricity generation in the Western Interconnection region of the U.S. might respond in circa 2030 to contrasting scenarios for fuel prices and greenhouse gas (GHG) emissions fees. We examine spatial and temporal variations in generation mix across the region and year using the PLEXOS unit commitment and dispatch model with a production cost model database adapted from the Western Electricity Coordinating Council. Emissions estimates are computed by combining the dispatch model results with unit-specific, emissions-load relationships. Wind energy displaces natural gas and coal in scenarios with relatively expensive natural gas or with GHG fees. Correspondingly, annual emissions of NOx, $SO_2$, and $CO_2$ are reduced by 20–40% in these cases. NOx emissions, which are a concern as a precursor of ground-level ozone, are relatively high and consistent across scenarios during summer, when peak electricity loads occur and wind resources in the region are comparatively weak. Accounting for the difference in start-up versus stabilized NOx emissions rates for natural gas plants had little impact on region-wide emissions estimates due to the dominant contribution from coal-fired plants, but would be more important in the vicinity of the natural gas units.

## 1. Introduction

Led by Wyoming, the eight states in the Rocky Mountain region (AZ, CO, ID, MT, NM, NV, UT, WY) account for more than 50% of U.S. coal production and 18% of natural gas production (EIA, 2016a). Coal production in the region peaked at over 600 million short tons in 2008 and fell to 480 million tons in 2015 (EIA, 2016a, 2016b). In 2015, the states in the Rocky Mountain region produced 5.1 trillion cubic feet of natural gas, up 6% from the level in 2005, with sharp growth in Colorado offsetting a decline in New Mexico and relatively stable production in Wyoming (EIA, 2016a, 2016c). Since 2010, utilities in the region have completed or announced plans to retire or repower more than 20 coal-fired power plant units. Electricity generation in these states shifted from 63% coal, 19% natural gas and less than 1% wind in 2005, to 52% coal, 22% natural gas and 5% wind in 2014 (EIA, 2016d).

Shifts to natural gas and renewable energy are expected to continue in the western U.S., with significant implications for the region's air quality. Electricity generation and energy production activities are major sources of nitrogen oxides (NOx), sulfur oxides, volatile organic compounds (VOC) and greenhouse gases (GHG). Except for Idaho and Montana, all of the states in the Rocky Mountain region include areas that have been designated nonattainment for the 2008 National Ambient Air Quality Standard for ozone or have recent ozone values above the 2015 revised standard (EPA, 2016a), so emissions of ozone precursors – NOx and VOCs – are of particular concern. Understanding how the changing energy landscape might affect future emissions and air quality in the Rocky Mountain region requires a combination of energy and air quality models that bridge across hourly to decadal time scales.

The objective of this study is to examine the sub-regional spatial patterns and sub-annual temporal patterns of electricity sector emissions within the Rocky Mountain region that might result from contrasting scenarios for future natural gas prices and greenhouse gas mitigation policies. The study builds on prior work by McLeod et al. (2014), who used the U.S. Environmental Protection Agency's (EPA) nine-region MARKAL energy system model to examine how annual

*Abbreviations:* CSP, Concentrating Solar Power; EIA, Energy Information Administration; EPA, Environmental Protection Agency; ERCOT, Electric Reliability Council of Texas; GHG, greenhouse gases; NREL, National Renewable Energy Laboratory; PAWY, PacifiCorp East – Wyoming; PSCO, Public Service Company of Colorado; PV, photovoltaics; RPV, rooftop photovoltaics; TEPPC, Transmission Expansion Planning Policy Committee; VOC, volatile organic compounds; WACM, Western Area Power Administration – Colorado-Missouri; WECC, Western Electricity Coordinating Council

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http://dx.doi.org/10.1016/j.enpol.2017.07.051
Received 20 February 2017; Received in revised form 6 June 2017; Accepted 23 July 2017
0301-4215/ 

average emissions would respond to these scenarios out to the year 2050, for the entire U.S. and for the Rocky Mountain region as a whole. To begin to examine spatial and temporal patterns within the Rocky Mountain region, the current study "downscales" the electricity sector emissions estimates for this region for a circa 2030 time period. To do this, we simulate the electricity generation mix in selected scenarios at hourly temporal resolution using the PLEXOS unit commitment and dispatch model for the power plant fleet expected to be in place in the Western Interconnection at that time. Hourly variations in hydro, wind and solar resource availability and electricity demand are estimated from historical data, which are then scaled by increased overall demand and renewable electricity capacity for the future scenarios. Emissions are computed by combining unit-specific loads from the dispatch model with load-dependent emissions factors.

To our knowledge, this is the first such study for the Rocky Mountain region, and the first study in any U.S. region to provide this level of detail for a future timeframe when significantly expanded capacity for renewable energy could be in place to compete with natural gas and coal. Future work will combine the electricity sector emissions results described here with estimates of emissions changes from upstream energy production, and use these as inputs to a regional-scale chemistry and transport model to study net air quality impacts of natural gas production and use.

## 2. Background

The U.S. EPA, U.S. Energy Information Administration (EIA) and other Department of Energy laboratories have long used least-cost or partial equilibrium energy system or power sector planning models to examine emissions impacts of future electricity generation or broader energy scenarios and to analyze proposed emissions control strategies and other regulations. These models include EIA's National Energy Modeling system (EIA, 2013) used to produce their Annual Energy Outlook; EPA's MARKAL model and nine-region U.S. database (Lenox et al., 2013); the Integrated Planning Model (EPA, 2014) used in regulatory analyses such as those for EPA's Cross-State Air Pollution Rule (EPA, 2016); and the National Renewable Energy Laboratory's Regional Energy System Deployment (ReEDS) model (Eurek et al., 2016; Cole et al., 2016). Researchers have used these and similar models to examine a range of scenarios and policy proposals. For example, Brown et al. (2013, 2017) applied MARKAL with EPA's nine-region database to examine how adding damage-based fees in the electric power and other U.S. energy sectors would alter emissions. Trail et al. (2014) used emissions from EPA's MARKAL reference case to examine how air quality across the U.S. might change by 2050. Thompson et al. (2014, 2016) used the U.S. Regional Energy Policy model to estimate conventional air pollutant emissions responses to greenhouse gas mitigation strategies. In work that forms the basis for the current study, McLeod et al. (2014) modified EPA's MARKAL model with updated information on costs of renewable energy and emissions from oil and gas production, then used the revised model to examine how contrasting scenarios for natural gas supply and demand, constraints on the electricity generation mix, and GHG fees might affect energy system emissions for the U.S. and the Rocky Mountain region out to the year 2050. These studies all focus on projecting annual average emissions changes at the state, regional, or national scale. In studies that estimate air quality impacts from the energy and emissions modeling results, the projected annual changes in emissions are typically used to scale existing emissions inventories up or down, assuming the location and sub-annual timing of emissions will not change (e.g., Thompson et al., 2014, 2016).

Higher resolution in emissions projections is critical for examining how alternative economic or policy scenarios might influence emissions during specific time periods that are prone to air quality problems (Hobbs et al., 2010; Krieger et al., 2016), e.g., on hot summer days when electricity demand is high, wind availability tends to be low, and meteorological conditions are conducive to ozone formation. Fig. A1 in Appendix A illustrates such conditions, showing the correlation between temperature, power plant load and ozone for Denver, CO in July 2006. Recent studies have started to conduct electricity system analyses that provide higher resolution, by using electricity dispatch models or simplified representations of dispatch order to estimate emissions changes in response to altered demand, fuel prices, or policies to encourage renewables (e.g., Hobbs et al., 2010; Brinkman et al., 2010; Thompson et al., 2011; Plachinski et al., 2014). For example, Gilbraith and Powers (2013) applied a dispatch model to simulate residential demand response in New York City, finding that a moderate program could reduce generation from small, relatively inefficient combustion turbines used to meet peak demand, thus reducing NOx and $PM_{2.5}$ emissions on poor air quality days. Buonocore et al. (2015) applied a dispatch model for the Eastern Interconnection to compare the emissions and corresponding health benefits of incorporating wind, solar, and demand response at six locations in the eastern U.S., illustrating how the benefits depend on the type and location of fossil fuel generation being displaced. Kerl et al. (2015) used a reduced-form air quality model relating emissions to pollutant concentrations and monetized estimates of resulting health effects to generate environmental damage costs for inclusion in a least-cost electricity dispatch algorithm for power plants in Georgia. Including environmental costs in the dispatch algorithm led to shifting generation on some winter days from coal-fired power plants in northern Georgia to a natural gas combined cycle plant near the coast.

Pacsi et al. (2013) used the PowerWorld Simulator to estimate how hourly generation from units in the existing Electric Reliability Council of Texas (ERCOT) system depends on natural gas prices, as an input to an assessment of net air quality impacts from natural gas production in the Barnett shale. They estimated NOx emissions for each unit by multiplying hourly generation with the unit's annual average emissions factor. Net impacts on ozone air quality in Texas were modeled using a regional atmospheric chemistry and transport model, CAMx (Comprehensive Air Quality Model with Extensions), adjusting the power plant NOx emissions and estimates of NOx and VOC emissions from local natural gas production in each gas price case. Pacsi et al. (2015) conducted a similar net air quality analysis assuming the natural gas came from the Eagle Ford shale, instead of the Barnett.

Compared to prior emissions studies using dispatch modeling, this study is unique in focusing on the Rocky Mountain region, which has abundant wind and solar resources as well as coal and natural gas. We examine relatively broad and self-consistent scenarios for key factors that could shape future electricity generation in the region, covering a range of natural gas prices and greenhouse gas mitigation policies. Unlike other studies that have considered limited adjustments to the current electricity system, we examine dispatch results for a future electricity generating fleet that reflects utilities' current plans for retiring or repowering coal plants. Lastly, unlike most prior studies, we use detailed unit-specific emissions models that account for load-dependence of emissions rates.

## 3. Methods

### 3.1. Scenarios

The natural gas price and emissions fee scenarios and corresponding renewable energy build outs considered in this study were developed by McLeod et al. (2014), using the MARKAL model with the EPA U.S. nine-region database. The MARKAL model finds the least cost means to satisfy future end use demand in the industrial, commercial, residential, and transportation sectors, under specified constraints including limits on fuel supplies and on rates of capacity expansion and introduction of new technology. The EPA database available at the time was developed to match projections from Energy Information Administration's 2012 Annual Energy Outlook. McLeod et al. (2014) modified the 2012