An Integration Cost Study for Solar Generation Resources on the Public Service Company of Colorado System

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Executive Summary

This report presents the findings of an updated integration cost study for solar PV generation on the Public Service Company of Colorado ("Public Service") electrical system. The study methodology is similar to that employed in prior wind and solar integration cost studies. Integration costs were assumed to derive from the uncertainties in a real-time operator's day-ahead commit and dispatch decisions. These types of studies require a unit-commit and dispatch model of an electrical utilities loads and generation resources; they also require hourly day-ahead load forecasts and realized load pairs and hourly day-ahead solar generation forecasts and realized solar generation pairs.

In the Company's prior solar integration cost study, day-ahead forecast error was calculated between the realized hourly solar generation and a day-ahead forecast of solar generation based on the average generation expected for each hour in a given month. In 2011, the National Renewable Energy Laboratory ("NREL") created and published estimated day-ahead forecast solar generation and realized solar generation pairs for thousands of locations across the country including Colorado. Those NREL data sets were employed in this study.

Solar integration costs calculated in this study are quite low and roughly an order of magnitude less than in the prior study on the Public Service system. The relatively low results support NREL's findings regarding the difference in integration cost drivers between solar generation and wind generation. Specifically, wind integration costs are predominately driven by forecast uncertainty and, thus, the methodology utilized in this and in prior integration studies remains applicable to wind generation. However, solar integration costs will predominately be driven by short-term variability and, thus, the methodology utilized in this study is less applicable.

This study examined only those system operational costs that are assumed to occur due to solar generation forecast uncertainty. No other potential costs of solar integration were examined in this study including those related to the location of solar generation. For example, no analyses of potential integration costs arising from significant penetration rates of solar on individual distribution feeders were conducted.

Table of Contents

Introduction

Background

Wind and solar PV generation resources are non-dispatchable (outside of the ability of a reliability organization to curtail generation), intermittent, and at times challenging to forecast. Their inclusion in a portfolio of other generation types can impose incremental operational costs on the entire system. The Company has in the past conducted wind and solar integration cost studies with results that have been applied in resource planning and resource acquisition processes in order to create generation portfolios that are cost-effective across a range of planning scenarios.

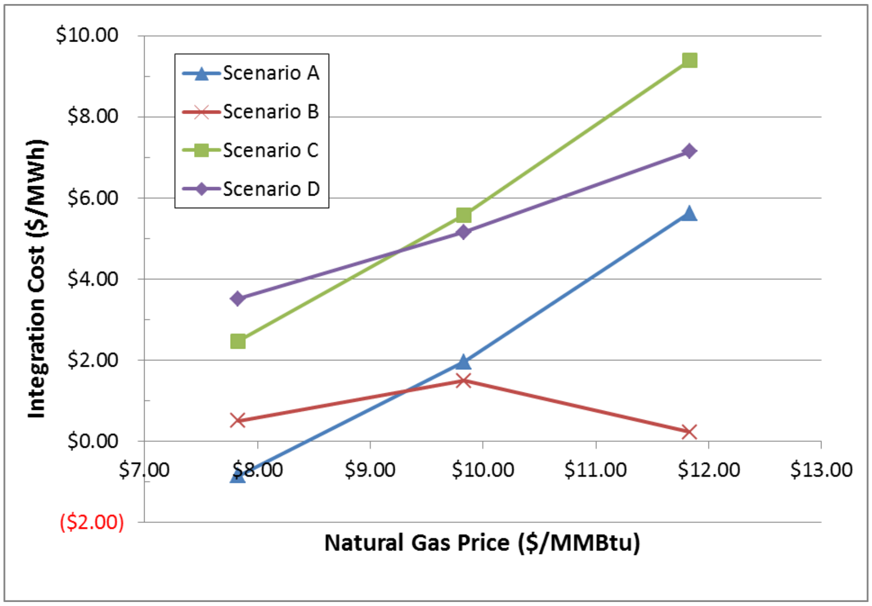
Prior Solar Integration Cost Studies

The Company has conducted one prior solar integration cost study (completed in February 2009) that examined integration costs associated with the uncertain and variable nature of solar generation;[1] at the time of the 2009 solar integration cost study the Company had ~25 MW_{DC} of interconnected solar generation.[2] In that study the Company examined incremental solar generation levels from 200 MW to 800 MW across a variety of solar technologies: fixed PV, tracking PV, and solar thermal troughs with and without thermal energy storage. Of particular note was that each scenario examined included a minimum of 200 MW of solar trough generation with 4 hours of thermal energy storage.[3] The results of the 2013 solar integration cost study are shown in Figure 1 below as a function of the gas price range examined.[4]

Current natural gas price forecasts are significantly lower than the range of prices examined in the 2009 integration cost study; currently-forecasted, average annual natural gas prices do not reach the ~$7.80/MMBtu minimum levels examined in the 2009 study for between fifteen and thirty years.[5]

[1] "Solar Integration Cost Study for Public Service Company of Colorado", Xcel Energy Services, Inc. and EnerNex Corp, February 9, 2009.
[2] Unless otherwise indicated, the terms "MW" and "MWh" in this study report refer specifically to MW_{AC} and MWh_{AC}.
[3] Scenarios A, B, and C were composed of 200 MW, 400 MW, and 600 MW respectively of solar troughs with thermal energy storage all located in the San Luis Valley of Colorado. Scenario D included 100 MW of PV located in the Southern Front Range of Colorado near Pueblo and 100 MW of PV located in the Northern Front Range near Denver in addition to the 600 MW of solar trough generation in Scenario C for a total of 800 MW of solar generation.
[4] The anomalous reading at the high gas sensitivity case for Scenario B as shown in Figure 1 in which solar integration costs decrease at higher gas prices was unexplained in the study report.
[5] Average natural gas spot prices at the CIG Rocky Mountain hub have averaged $2.23/MMBtu over the past twelve months. The Company's current annual base gas price forecast achieves an $8.00/MMBtu price in 2045 and its high gas price sensitivity gas achieves an $8.00/MMBtu price in 2030.

Figure 1 2009 Solar Integration Cost Study Results



Currently-Installed Levels of Solar

At the end of 2015, the Company had ~370 MW of interconnected solar generation located across the state of Colorado at nearly 30,000 sites as illustrated in Figure 2 below. Additional detail as to the distribution of existing solar generation is provided in Table 1 below.

Figure 2 Solar Resource Zones and Installed Solar Locations

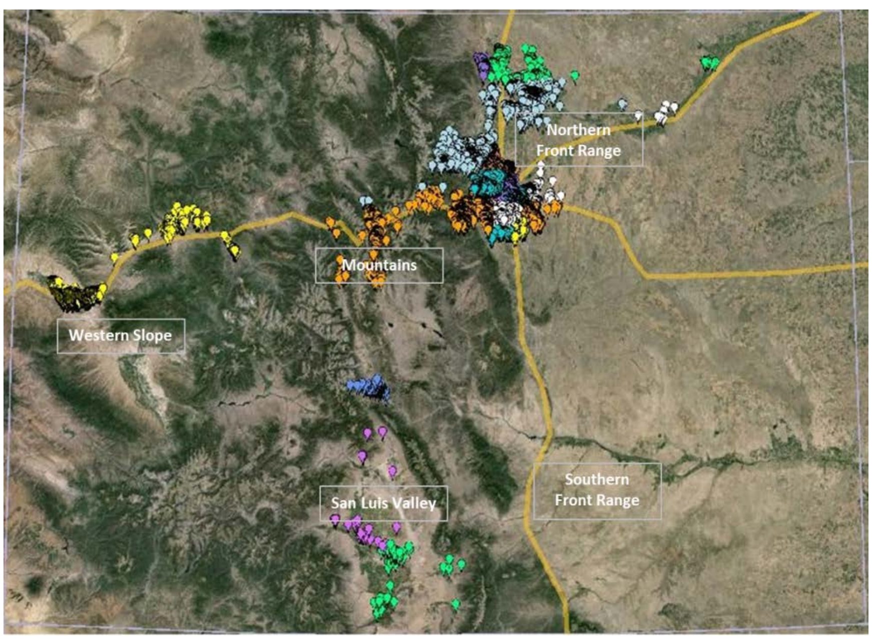


Table 1 Solar Generation Portfolio by Geographic Location and Tracking Capability[6]

	MW		
Solar Resource Zone	**Fixed**	**Tracking**	**Total**
Mountain (MTN)	3		3
Northern Front Range (NFR)	200	6	207
San Luis Valley (SLV)	3	138	140
Western Slope (WS)	19	2	20
	225	145	370
Southern Front Range (SFR)[7]		120	120
	225	265	490

Of the ~370 MW of installed solar at the end of 2015, ~155 MW have been acquired through purchased power agreements including contracts from five, large-scale tracking units in the San Luis Valley and from smaller solar garden-type facilities located across Colorado. The remaining ~215 MW have been installed behind our customers' meters at ~30,000 sites; 85% of the 215 MW have been installed within the Company's Denver metro area load center (Northern Front Range) in fixed orientations.

Study Methodology

The Company's methodology in this solar integration cost study is similar to that employed in the 2009 integration cost study and previous wind integration cost studies. In those studies integration costs were assumed to derive from the uncertainties in a real-time operator's day-ahead commit and dispatch decisions. These types of studies require a unit-commit and dispatch model of the Company's loads and generation resources; they also require hourly day-ahead load forecasts and realized ("actual") load pairs and hourly day-ahead solar generation forecasts and realized ("actual") solar generation pairs. In this study the Company employed a PLEXOS® model representation of the Company's system in 2024.[8]

[6] Behind-the-meter solar generation resources are typically acquired and denominated in MW_{DC} terms. In this study, those generation resources have been denominated in MW_{AC} terms using a conversion factor of 0.85. Differences between individual values and totals in Table 1 are the result of minor rounding errors.
[7] The 120 MW Comanche Solar facility in the Southern Front Range is expected to be in-service by the summer of 2016.
[8] The PLEXOS® Integrated Energy Model software is licensed from Energy Exemplar.

The study methodology here estimates solar integration costs at a transmission-,system level. That is, it does not intend to capture any localized impacts of, for example, solar generation on a particular distribution feeder.

The study methodology captures two sources of cost due to forecast uncertainty: cost from uncertainty in the day-ahead load forecast and cost from uncertainty in the day-ahead solar forecast. Several model runs are needed to determine the costs due to the solar forecast uncertainty only:

1. In the first run, a unit commit schedule for coal-fired and gas-fired-combined cycle generators is determined based on the load and solar generation forecasts; operational costs are estimated.
2. In the second run, the load forecast is replaced by the "actual" load ("actual" solar profiles are unchanged from the prior run) and operational costs are calculated. The difference in operational costs of runs two and one is the cost due to load forecast error.
3. In the third run, both the load forecast and the solar forecasts are replaced with the "actual" values. The difference in operational costs of runs three and one is the cost due to load and solar forecast error.
4. The difference between the operational costs calculated in steps 3 and steps 2 are the costs assigned to the uncertainty in the solar forecast.

Study Goals

The Company's goals in this study were to estimate the operational costs due to solar generation forecasting errors at differing levels of solar installations (PV only) and as a function of assumed natural gas prices. Studies were conducted with assumptions of 1,000 MW of total installed solar and 1,800 MW of total installed solar. The base gas price assumption was $4.37/MMBtu and a high gas price assumption was $9.58/MMBtu.

Load Data Sources

The Company chose 2024 as the test year during which to estimate solar integration costs at the two solar penetration scenarios. Realized 2024 hourly load data were developed using the PLEXOS® model. Hourly forecast load errors for 2024 were assumed to be identical to actual hourly forecast load errors from 2011. That is, the required 2024 day-ahead hourly load forecast values were calculated by combining the 2024 hourly load data and the 2011 actual hourly forecast load errors. 2011 data were used as they are relatively recent and they have lower levels of distribution-interconnected solar generation (e.g., behind-the-meter solar generation) embedded in the hourly load values than do data from later years.

Solar Generation Data Sources

At the time the Company conducted the 2009 solar integration cost study it had no sources for day-ahead, solar generation forecasts. For that study, hourly solar generation forecast data were created by averaging the insolation for every hour for the entire month. For example, the solar forecast for any hour in the month of March was set equal to the average insolation for that hour across all March days. "Actual" hourly solar generation data were created based on satellite-derived solar irradiation data and assumed scenarios of generation resource types (both solar thermal and PV) in assumed locations that were then modeled with NREL's Solar Advisor Model.[9]

After the Company completed its 2009 study, NREL produced sets of hourly day-ahead solar forecast data and realized solar pairs for the 2006 calendar year in their Solar Power Data for Integration Studies work.[10] The Solar Power Data includes 88 geographic-specific forecast/realized generation profile pairs for "distributed solar generation" profiles ("DPV") and "utility-scale solar generation profiles" ("UPV") in Colorado.[11] Each of the ~30,000 existing behind-the-meter generators shown in Figure 2 was mapped to the nearest DPV profile resulting in 24 DPV profiles.[12] Each of the Company's existing and planned utility-scale solar generators were mapped to the nearest UPV profile; in addition, incremental utility-scale solar generators were mapped to other UPV sites in the Solar Power Data sets resulting in seven UPV profiles. Shown in Figure 3 are the DPV (green balloons) and UPV (blue balloons) locations within Colorado utilized in the study.

The Solar Power Data forecast/realized generation data shown in Figure 3 exist in corresponding locations to where the Company currently has interconnected solar generation (as shown in Figure 2) so as to adequately map the existing solar generators to the NREL data locations.

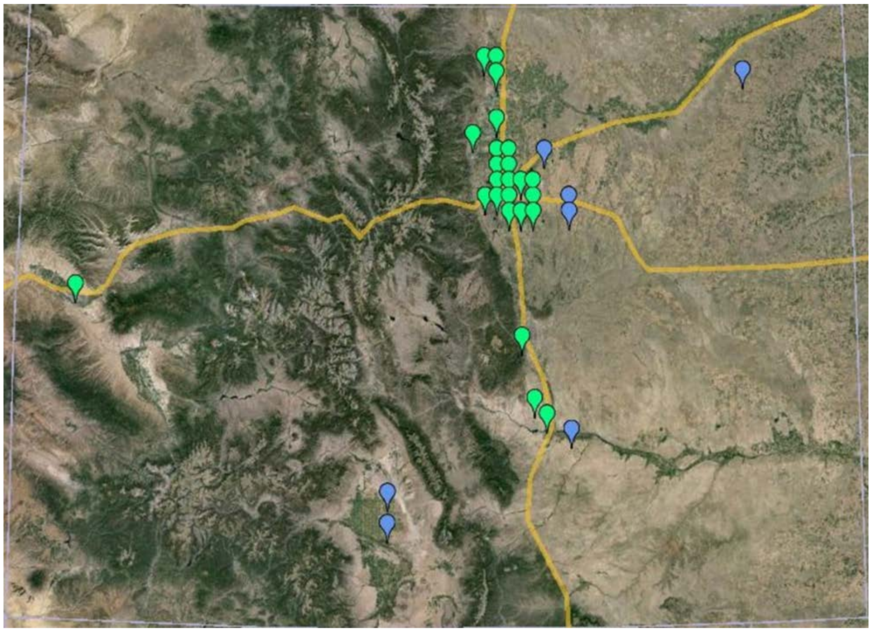
[9] NREL has expanded the capability of their original modeling tool and makes it available as part of its System Advisor Model.

[10] The Solar Power Datasets and a description of how the synthetic solar PV generation data were generated is available from NREL's Solar Power Data for Integration Studies website at:
http://www.nrel.gov/electricity/transmission/solar_integration_methodology.html

[11] DPV hourly profiles were created assuming fixed orientations; UPV hourly profiles were created assuming 1-axis tracking systems.

[12] Mapping of the existing generators was conducted using the latitude/longitude coordinates of the existing solar generators and the Solar Power Data locations; each existing solar generator was mapped to the nearest Solar Power Data location. Approximately 50% of the existing PV systems were mapped to a Solar Power Data location less than 5.5 miles away; 95% of the existing PV systems were mapped to a location less than 10.5 miles away.

Figure 3 DPV and UPV Data Sets Utilized in the Study



In order to study solar integration costs at higher penetrations than exist today, assumed locations for future PV systems were needed. For this study, future distribution-interconnected solar installations (e.g., behind-the-meter generators) were assumed to occur in the same solar zones and in the same ratios as the existing distribution-interconnected installations.[13] Future utility-scale solar installations were distributed across seven UPV locations and also at the DPV location on the Western Slope.[14] Table 2 below shows the assumed levels of installed solar generation for the two penetration rate scenarios studied.

Generation Portfolio

For the 2024 study year the assumed generation portfolio was based on the current schedules for changes at Company-owned coal-fired plants (184 MW retiring, 352 MW converting to natural gas) and expiring purchased power contracts for coal-based generation (150 MW total), gas-fired generation (379 MW total) and wind generation (192 MW total). An expansion plan that included 800 MW of incremental wind generation and four generic gas-fired combustion turbines was assumed to ensure that planning reserve margins were met.

[13] Given the low percentage of tracking systems currently installed behind our customers' meters, all DPV systems were assumed to be fixed. Existing DPV systems were converted to MW_{AC} terms and grossed up to transmission-interconnection equivalents to account for assumed transmission line losses.

[14] The 50 MW of UPV generation shown in Table 2 for the 1,800 MW Scenario was assigned to a DPV profile as the Solar Power Dataset has no UPV data at that location.

Table 2 Assumed Solar Generation Locations

Solar Resource Zone	1,000 MW Scenario (MW)		1,800 MW Scenario (MW)	
	Distributed	Utility-Scale	Distributed	Utility-Scale
Mountain				
Northern Front Range	677		994	280
San Luis Valley		132		182
Southern Front Range		120		190
Western Slope	71		154	
Total	748	252	1148	652

Unserved Energy

Unserved energy can occur within unit commit and dispatch models such as PLEXOS® when insufficient generation resources are available in any hour to meet the required load.[15] Unserved energy was shown to occur in the prior wind and solar integration cost studies using the model employed for those studies. The prior study model did not allow the flexibility to start uncommitted natural gas-fired combustion turbines as actual real-time system operators are allowed to do. In order to resolve the financial impacts of unserved energy in the prior wind and solar integration cost studies, post-processing or automated-processing routines were employed.

The PLEXOS® model, however, has the capability to allow for additional unit commitment in the real-time run. For this study, combustion turbines were allowed to commit in real-time while steam and combined-cycle units were not. Still, some small amounts of unserved energy were observed in the model output. It was noted, however, that the same levels of unserved energy appeared in both the initial run examining the financial impact of the load forecasting errors and the second case run examining the incremental financial impact of both the load and solar forecasting errors. As the financial impact of the unserved energy exists in each case and offset in the financial calculations, these small remaining levels of unserved energy have no impact on the final result. As such, no special process was utilized in this study to address unserved energy.

Study Results

Study results for the 1,000 MW and 1,800 MW cases are shown in Table 3 as a function of the two gas price scenarios.

[15] Unserved energy events are impacted by assumptions around schedule maintenance and randomly-modeled forced outage events.

Table 3 Solar Integration Costs ($/MWh)

Solar Generation	**Annual Natural Gas Cost**	
	$4.37/MMBtu	$9.58/MMBtu
1,000 MW	$0.01	$0.63
1,800 MW	$0.41	$0.74

Comparison to Previous Study Results

As shown in Figure 1, Scenario D from the previous study report was the only scenario which showed positive integration costs at gas prices below ~$6.00/MMBtu; as such, it is the study result that has been utilized in prior generation solicitation evaluations. The slope of a regression curve against the Scenario D results is approximately unity; that is, a $1/MMBtu change in natural gas price results in a $1/MWh change in solar integration costs. The slope of regression curves for the results in this study shown in Table 3 are roughly 0.10; that is, a $1/MMBtu change in natural gas prices results in a $0.10/MWh change in solar integration cost. Given the nearly negligible solar integration costs calculated in this study at low gas prices, either extremely high gas prices or extremely high penetration rates of solar would be required in order to have any meaningful impact on the adoption of solar generation.

Conclusions

Wind and PV solar are two fundamentally different types of intermittent generation. In the Phase 2 Western Wind and Solar Integration Study report, NREL described the difference as one in which "solar dominates variability and wind dominates uncertainty."[16] The Company believes the study methodology and the results from its prior wind integration cost studies continue to be applicable for wind generation. However, the Company does not believe that the study methodology/framework of that wind integration study (which was also applied in both the Company's 2009 and 2016 solar integration studies) is best suited to the analysis of solar generation at the levels of solar studied here; perhaps the methodology will find better application at higher levels of solar penetration. At currently-forecasted solar penetration levels, the low level of solar integration costs calculated in this study are not likely to be material in any decision to acquire incremental solar generation or not.

[16] "The Western Wind and Solar Integration Study Phase 2: Executive Summary", Technical Report. NREL/TP-5500-58798, September 2013. Pages 25-27.