Advanced Review

An assessment of price convergence between natural gas and solar photovoltaic in the U.S. electricity market

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The U.S. shale boom has exerted downward pressure on natural gas prices nationally, widened oil-to-gas price spreads, and accelerated coal-to-gas fuel substitution. One concern is the impact of the rising production of shale gas on further development of a domestic solar photovoltaic (PV) market. Specifically, will lower natural gas prices slow or even reverse the current rapid growth in the solar market? Using the Phillips–Sul convergence test, this paper investigates whether the levelized cost of energy (LCOE) of solar PV and natural gas electricity generation in the United States have converged. Using weekly Henry Hub-linked natural gas spot prices and utility PV system prices from 2010 to 2015, empirical tests for convergence are applied to examine the extent of spot market integration and the speed with which market forces move the two energy prices toward equilibrium. The paper also assesses the link between the MAC Solar Energy Index (SUNIDX) and the S&P GSCI natural gas index spot prices for evidence of market integration during 2007–2015. We conclude that PV and natural gas prices are not converging, and the two markets are not integrated nationally, but some level of integration could exist at regional and state levels that will need to be tested in future research. We also conclude that complementary use of the technologies is likely; while price convergence is not likely to occur soon, distinctive complementary benefits of each resource compared to each other (e.g., fast-start capabilities for gas and low price volatility for PV) will offer opportunities that expand market demand for both. © 2016 John Wiley & Sons, Ltd

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INTRODUCTION

The last 8 years have been a period of considerable transformative technological and economic change to the energy market in the United States. A proliferation of advanced clean energy technologies (from the renewable energy and energy efficiency sectors, as well as distributed energy resources such as rooftop solar and demand-side management) have triggered changes in the United States' century-old electricity system and the electric power sector in how various forms of energy are produced, transmitted, and sold. Compounding concerns about, for instance, climate change mitigation and adaptation requirements have prompted investigation into new menus of market, finance, and policy solutions for infrastructure-scale investment in energy transition pathways to substantially reduce carbon emissions.[1]

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Today's electric power sector is at a turning point. According to the Energy Information Administration (EIA), the U.S. electric power sector contributed nearly 39% of the total energy-related CO_2 emissions in 2014. Of these, coal and petroleum accounted for about 32 and 42%, respectively.[2] Recent developments in the natural gas market, especially the ability to cost-effectively extract vast, dispersed deposits of shale resources in the United States, have continued to transform the supply and price outlooks in the energy markets, affecting the choice of business models, fuel options, and domestic economic and environmental benefits. In particular, lower natural gas spot prices have motivated the displacement of other fuels with greater carbon intensity and higher pollution (such as coal in power generation). Fuel mix changes and carbon-intensive power plant retirements are projected to continue for the next two decades as (a) a combination of hydraulic fracturing and horizontal drilling technology makes it possible to economically access enormous quantities of natural gas from shale formations; (b) current and planned regulatory requirements complicate the business case for high-carbon emitters; and (c) electricity markets become more competitive.[3,4] Indeed, static coal prices, underutilized natural gas power plant capacity, and recent environmental regulations at the local, state, regional, and federal levels have encouraged the switch to fuels with lower emissions profiles, including natural gas and renewables.[5,6] Between 2005 and 2013, natural gas demand for power generation grew by 43%, and it is projected to increase to 27.6 Bcf/d by 2030 (representing a 250% growth).[7,8] On the other hand, consumption of coal for electricity generation declined by 17.2% during the same time frame, and it is projected to drop by 35.6% by 2030.[7]

Strong production growth in lower-cost unconventional gas, combined with a lack of export capacity, has fueled concerns of a second displacement effect: the possibility of natural gas 'crowding out' utility PV.[9–11] For instance, energy procurement decisions could favor low-cost natural gas' established profile over the intermittent, relatively new, and typically more expensive profile of utility PV. While much focus in the energy market integration and price convergence literature has been directed toward the relationship between natural gas and oil, [12–14] less attention has been paid to renewable energy, especially PV and its relationship with natural gas prices.[10] Therefore, as energy economic decisions get recast, and trends in carbon emissions shift, the interaction between depressed natural gas prices due to strong U.S. shale growth and PV market development remains largely unclear.

In this paper, we investigate the relationship between natural gas spot prices and utility-scale solar PV installations in the past 8 years in the U.-S. markets based on the levelized cost of energy (LCOE) approach.[a] We particularly assess whether or not PV and natural gas prices in the United States have been integrated or trending toward convergence since 2008. When two or more time series with stochastic trend move together so closely over the long run, such that they seem to have the same trend component, i.e., 'common trend,' they are said to be cointegrated.[15] The terms *market integration* and *price convergence* are both frequently used in the energy and commodity markets literature, and an explanation of how they relate to each other is necessary.

Market integration refers to a scenario where prices are positively correlated with each other, i.e., there is synchronous movement of prices of a commodity at two different markets over time in a particular direction.[16] Most literature on market integration uses the Law of One Price (LOP) as the theoretical foundation for determining prices of homogeneous products traded in geographically separated markets.[17] However, if we adopt Stigler and Sherwin's (1985) definition of a market as an area defined by similarity in price movements rather than geographical distance, the test can also be applied to diversified products such as PV and natural gas.[18] Whilst the concept of an integrated market has sometimes been vague, we view it as a situation in which natural gas prices are comparable across the country after accounting for transport costs, and consumers located within one part of the country may freely enter into a contract with any supplier or producers located in other regions. Accordingly, we adopted cointegration analysis,[19,20] the most used econometric method for assessing market integration.[21–23] Price convergence, on the other hand, refers to the process by which futures price (i.e. cash price and cost of carry such as storage, insurance, interest, and other incidental costs) gradually converges to the contemporaneous underlying spot price. A considerable number of studies have applied the idea of convergence to various energy and environmental topics, including convergence of carbon dioxide emissions across country data, [24–26] stochastic convergence of cross country emissions,[27] or convergence of energy data.[28–34]

Given the ongoing structural changes taking place in both renewable energy and natural gas markets over the period considered, two different approaches have been used, namely cointegration analysis and a time-varying coefficient model. The explicit presence of time-varying parameters, i.e., the presence of potential breaks in both natural gas and PV prices, makes the latter technique better suited for our analysis than the cointegration approach because it can capture contextual changes.[22,35,36] However, we applied both approaches to (1) make it possible to identify special events within the whole period studied and (2) because the two methods complement each other. For instance, if a given market was undergoing the process of integration during the study period, 'the cointegration approach may lead one to conclude that the market is not integrated, even if convergence and integration have been accomplished during the latter part of the period.'[37] On the other hand, the time-varying market integration approach (Kalman filter) does not reveal the full market picture, especially where the 'market integration question involves the interaction of more than two prices.'[37]

The paper is structured as follows: *Natural Gas Market Characteristics* section focuses on the U.S. energy market, with particular attention to the available literature on natural gas and solar market convergence. In addition, the section makes some initial observations on the PV and the natural gas price developments using market indices. *Methodological Approach* section presents the methodological framework and introduces the data for analysis. *Data Description and Empirical Analysis* section outlines the implementation of the econometric tests of convergence, and *Maintaining a Goldilocks Range of Natural Gas and PV Prices* section concludes the paper.

THE U.S. UTILITY PV AND NATURAL GAS MARKETS

This section provides a brief overview of the domestic natural gas and PV market, including production, consumption, and infrastructure-scale development. Of particular relevance is the discussion on market interactions between PV and natural gas markets, which may explain differences in the respective prices and the ongoing U.S. energy market transformation.

Utility-Scale Solar PV Market Characteristics

Residential-, commercial-, and utility-scale solar installations have grown rapidly in the United States during 2007–2015, and this trend is projected to continue into 2020 (Figure 1). Cumulative operating PV capacity, including all types of PV market segments (utility, residential, and commercial), surpassed the 25 GW mark as of the end of the fourth quarter of 2015, up from just 2 GW at the end of 2010.[38] The Solar Energy Industries Association (SEIA) and Greentech Media (GTM) have estimated that 14.5 GW of new PV installations will come online in 2016, up 94% over 2015, with utility PV accounting for nearly three-fourths of new capacity.[38] The continued growth of the solar market in the United States in the second quarter of 2016 marked the 10th consecutive quarter in which utility PV added at least a gigawatt-level capacity. As a result, the United States, as of June 2016, had more than one million operating solar PV installations, producing 27.5 GW.[38]

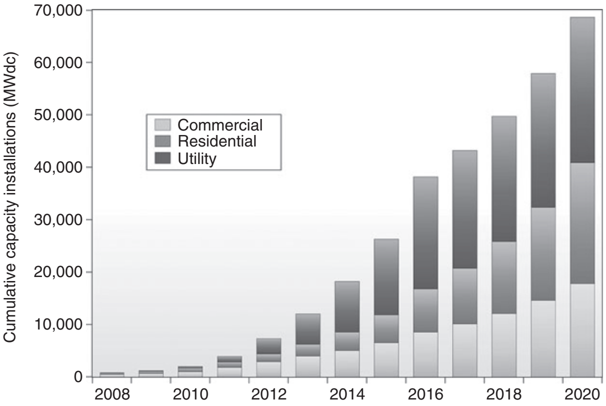

FIGURE 1 | Development of the U.S. PV market categorized by residential, nonresidential, and utility-scale PV installations. Notes: The total U.S. PV capacity additions are based on GTM Research and SEIA (2010–2015), IREC's data collection, and LBNL's Tracking the Sun database. GTM, Greentech Media; PV, photovoltaic; SEIA, Solar Energy Industries Association.

For the first time in 2014, utility PV became an economically competitive energy resource to meet utilities' peak power needs, a value proposition that continues to spread across the renewable energy market.[38] In 2015, solar continued to drive an increasing portion of new electric generating capacity additions, surpassing natural gas for the first time on an annual basis. SEIA forecasts that the utility PV market will continue to be the bedrock driver of U.S. solar installations, accounting for 43% of capacity installed in the first quarter of 2016 across market segments.[38] For instance, in Southeast states, with a particular focus on Georgia, Florida, and the Carolinas, utility PV capacity additions will increase more than 10-fold due to inexpensive utility PV power-purchase agreements (PPAs), reflecting the ability of utility-scale solar to both compete with and complement new natural gas plants.[38]

Looking ahead, the SEIA and GTM Research highlight the importance of these market trends for U.S. solar: [38]

> Key trends to keep an eye on include development of utility PV projects that leverage the Public Utility Regulatory Policies Act to secure PPAs priced at utilities' avoided costs of peaking generation; corporate procurement of offsite solar via direct access programs or power hedge contracts; and the emergence of Texas plus Southeast state markets, where utilities are displacing coal fleets with natural gas and solar.

The utility PV pipeline corroborates the importance of the utility sector; a total of 16.6 GW of utility-scale solar PV power generation has either been contracted or is currently under construction (Figure 2).[b] Moreover, an additional 30.7 GW is currently in the precontract stage. Concerted national efforts, such as the extension of the federal Investment Tax Credit (ITC), along with the timing of several state-level policy developments are driving regional PV market development as California, North Carolina, Nevada, New York, and Massachusetts have emerged as the top five U.S. states for PV installations, and New Jersey ranks seventh behind Arizona in PV installation capacity as of January 2016.[39] A growing number of states have redesigned their electricity markets to accommodate the growth of distributed energy resources,[40] notably California (through AB 327 and its offshoots) and New York (through the Reforming the Energy Vision 'REV' initiative). Looking into the future, other states are likely to implement similar improvements in their business models in the future.[41] Cost reductions will further contribute to the role played by (utility-scale) PV in energy market development; SEIA-modeled costs fell to \$1.49/Wdc and \$1.71/Wdc in the second quarter of 2015, from \$1.58/Wdc and \$1.80/Wdc in the previous quarter, for fixed-tilt utility PV and one-axis tracking technology, respectively.[39] In the first quarter of 2016, prices of utility fixed-tilt and tracker ground-mount systems averaged \$1.24/Wdc and \$1.41/Wdc, respectively, with both hardware and soft-cost reductions contributing to lower overall system pricing.[38]

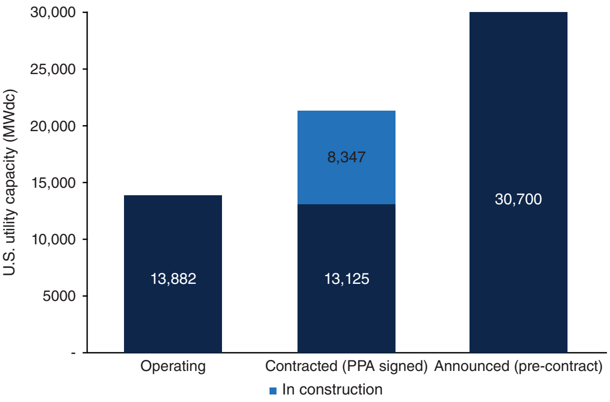

FIGURE 2 | The utility PV project pipeline indicates strong future growth in the sector.[39,40] PV, photovoltaic.

Natural Gas Market Characteristics

Driven by deregulation and open access to interstate gas pipelines, the emergence of active spot wholesale markets has contributed to a strong growth in domestic gas production.[42] At the end of the second quarter of 2015, the market segment of small producers (the United States is home to over 10,000 small producers, each of whom produce less than 1000 barrels of oil equivalent of oil and gas per year) supplied nearly one-third of the U.S. gas production, while other major companies supply the rest —excluding imports, which provide about 7% of total supply.[6]

According to the EIA, about 9.35 trillion cubic feet of dry natural gas was produced in the United States in 2013. At 3.65 trillion cubic feet, shale gas represents about 39% of total dry natural gas production.[c] Figure 3 provides estimates of the U.S. dry natural gas production (million cubic feet) from major producing states. Of particular significance is the strong growth in natural gas production in Pennsylvania driven by the shale gas boom in the state. Continued growth in shale gas production is already exerting pressure on natural gas prices, with the potential to fundamentally transform the industry.[43]

Additionally, the shale gas boom illustrated in Figure 4 has significant consequences for natural gas prices, especially in states such as Pennsylvania, Texas, and Oklahoma. The U.S. natural gas market has a highly competitive spot market where gas is traded daily along the market centers. In particular, the Henry Hub and Waha Hub in Texas (SONAT) are two major pricing points in the Louisiana-Onshore South region. Located in Louisiana, the Henry Hub connects with nine interstate and four intrastate pipelines, enabling companies to readily access daily market gas prices and other relevant information.[42] Before the establishment of FERC Order 436 on 'open access' reforms in the 1980s and early 1990s, little market information could be gained from the inter- and intrastate pipeline system. Open access regulatory reforms completely changed the market by decoupling gas production and trading

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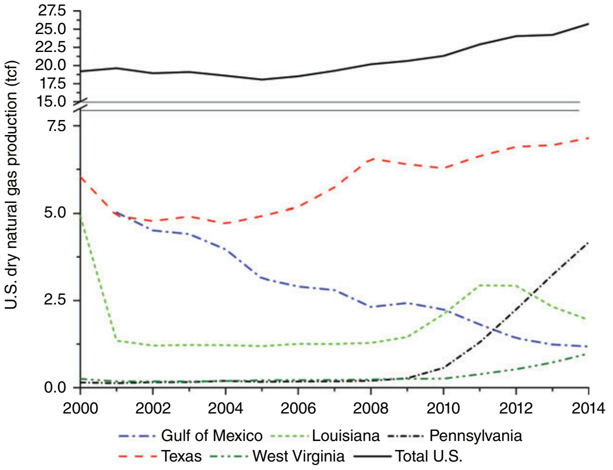

FIGURE 3 | Major gas-producing states. Notes: Data for 2014 are estimated. Monthly preliminary (from January 2014 to present) state-level data for the production series, except marketed production, are not available until after the final annual reports for these series are collected and processed. From 2007 onward, gross production from coalbed methane and shale data are obtained from PointLogic Energy. Coalbed methane refers to methane generated during coal formation and is contained in the coal microstructure. Typical recovery entails pumping water out of the coal to allow the gas to escape. Methane is the principal component of natural gas. Coalbed methane can be added to natural gas pipelines without any special treatment.

from its transportation function.[42] Figure 5 highlights daily natural gas price series at the Henry Hub and Waha Hub from January 2008 to December 2015.

In the past decade, U.S. gas prices have experienced high price volatility and supply–demand imbalances. In October 2014, the Henry Hub gas spot market traded in the $3.8/MMBtu for the $4/MMBtu range. In 2014, gas spot prices averaged $4.45/MMBtu and less than $3/MMBtu in 2015 according to EIA.[44] Although price differentials exist between different regional gas markets because of transportation costs, it is likely that big importers targeting the U.S. shale boom, such as South Korea and Japan, will benefit from additional alternate suppliers with lower costs, a development that will continue to benefit countries importing the cheap U.S. gas so long as the shale growth continues.[45]

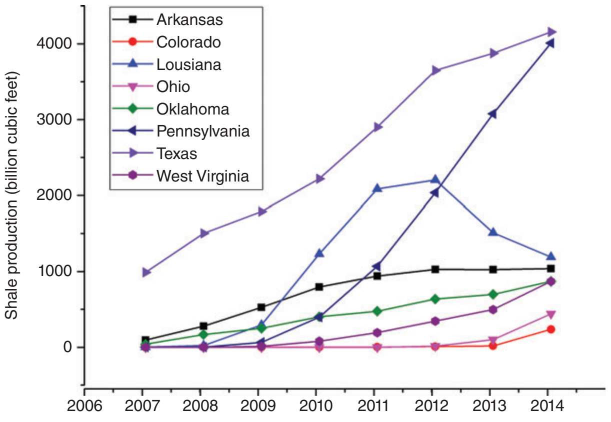

FIGURE 4 | Growth in shale production gas.

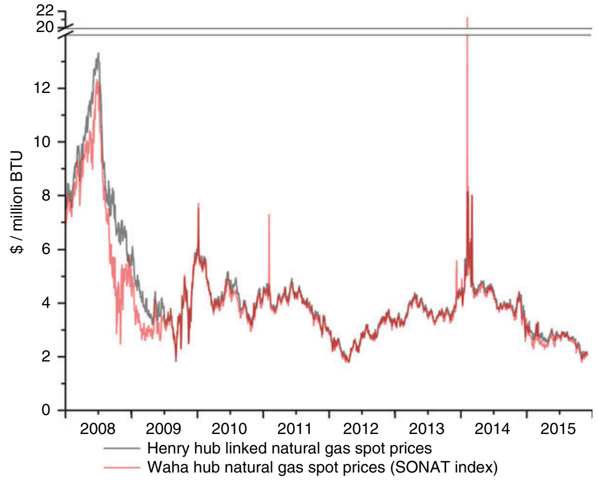

FIGURE 5 | Historical changes in daily natural gas spread 2008–2015.
Notes: Prices are based on delivery at the Henry Hub in Louisiana. Official daily closing prices at 2:30 p.m. are obtained from the trading floor of the NYMEX for a specific delivery month. The NGPL composite price is derived from daily Bloomberg spot price data for natural gas liquids at Mont Belvieu, Texas, weighted by gas processing plant production volumes of each product as reported on Form EIA-816, 'Monthly Natural Gas Liquids Report.' The SONAT Index is a monthly cash-settled Exchange Futures Contract based on the mathematical result of subtracting the monthly price published by Inside FERC, as defined in Reference Price B (Natural Gas-Southern Natural (Louisiana)-Inside FERC), from the average of the daily prices published by Gas Daily, as defined in Reference Price A (Natural Gas-Louisiana (Southern Natural)-Gas Daily). Price quotation convention is one hundredth of a cent ($0.0001) per MMBtu. NGPL, natural gas liquids; NYMEX, New York Mercantile Exchange.

Theoretical Interaction between PV and Natural Gas Price Points

In terms of the interaction between natural gas and PV price points, a 'Goldilocks' theory has been offered where market prices are 'neither too hot nor too cold' to stimulate natural gas and PV market development.[46] In other words, the Goldilocks theory holds when the right natural gas price leads to the highest level of solar output, i.e., when there is an effective partnership between solar energy and natural gas. This range should ideally establish investment incentives and macroeconomic equilibrium for both PV and natural gas producers ‘without creating too powerful a feedback effect on consumer economies and without overly endangering one producer,’[46] In terms of natural gas prices, the Goldilocks principle refers to the ‘idea that when natural gas prices are low, solar energy growth declines because solar looks expensive to consumers. Conversely when natural gas prices are high, electricity as a whole becomes less affordable, then consumers become less receptive to installing solar because they see it as an added expense.’[47]

Under the right conditions, synergistic interaction between natural gas and solar energy is possible at multiple levels, including the development of hybrid energy systems, joint investment and financing, colocation of facilities, creation of infrastructure-scale joint transmission corridors, wholesale power markets, and joint coordination between the two resources.[48] Additionally, due to the rapid growth of renewables, rising grid parity conditions, and shale gas expansion in the United States, utility business models are being revised from the conventional investor-owned energy paradigm toward the energy service utility model.[49] Such a positioning of new utility business models promises to yield better response to the potential synergy between the two energy sources.[48]

However, low natural gas prices, when falling below ‘Goldilocks’ parameters, could degrade the investment profile of utility-scale PV. Using Power Systems Optimizer (PSO) modeling of utility-scale PV and natural gas grid additions and price convergence, Shavel et al. (2014) simulated how renewable energy and natural gas-fired electricity generation systems would develop on the ERCOT system through 2032.[50] Weiss et al. (2013) examined the interactions between the natural gas and renewables markets in ERCOT, both in the short and in the long term.[10] Both studies concluded that, in the short run, low natural gas prices are unlikely to affect investment in rooftop PV or utility-scale solar due to the absence of fuel costs. However, in the long run, the studies emphasized the complementary relationship between the solar and natural gas and simulated the expected displacement of existing coal-fired generation. Renou-Maissant (2012) used both cointegration analysis and time-varying parameter models to analyze gas prices of six western European countries for the period 1991–2009.[51] She applied Kalman filter analysis to test whether natural gas prices in the six EU markets were converging. She found evidence of an ongoing process of convergence of industrial natural gas prices in France, United Kingdom, Italy, Belgium, Germany, and Spain since 2001 and concluded that there is a strong integration of these markets in continental Europe, except for Belgium. While some of these studies have treated natural gas and renewable energy sectors as direct competitors and adversaries, our analysis focuses on their complementary attributes and potential for greater partnerships from the perspective of electricity portfolio and market design. Joint platforms of dialogue and collaboration between natural gas and renewable energy industries that are required to define and frame current and future policy questions in the electric power sector exist in system integration, hybrid technology opportunities, and power sector market design.[48]

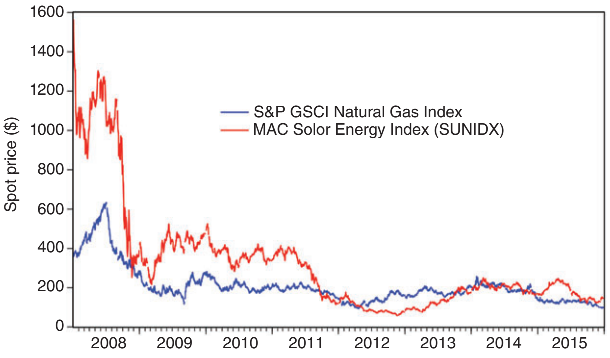

FIGURE 6 | Performance of solar and natural gas indices from 2008 to 2015.

Observation of Interaction between PV and Natural Gas Prices

This section describes two major indices in the solar and natural gas industries and how price points have developed. The section evaluates how both price points appear to show some level of convergence, but a further test, which is conducted in the next section, is necessary. Between 2008 and 2013, natural gas prices fell by 66%, while the MAC Global Solar Energy Index (SUNIDX) price dropped by nearly 90%. Figure 6 shows the performance of the MAC Solar Index (the tracking index for the Guggenheim Solar exchange traded funds (ETF) (NYSE ARCA: TAN)) and the S&P GSCI natural gas index. SUNIDX[d] and S&P GSCI indices measure performance and price movements of solar energy (solar PV and thermal solar power) and natural gas companies, respectively. MAC Solar Energy Index tracks globally listed public companies that specialize in providing solar energy products and services. SUNIDX’s performance does not reflect transaction costs, fees, or expenses of solar ETF. S&P GSCI[e] is widely recognized as a leading measure of the general price movement and inflation in the world economy.

The price developments in Figure 6 show a 2% drop in the SUNIDX in 2015. Nevertheless, the fundamentals of the solar industry remained favorable during the year, with strong end-user demand, stable polysilicon and solar wafer, and cell and module pricing (see Table 1). The data series in the figure suggests that the PV and natural gas prices that were quite widely spread during early 2008 began to fall and converge after January 2011 but started to rise and diverge after May 2011. This appears contrary to what would be expected considering the United States installed approximately 1600 MW of grid-connected PV capacity in 2011 (inclusive of all types of PV), representing a 74% increase over the 918 MW installed in 2010.[52,53] Including all types of PV, cumulative installed capacity grew from 200 MW to 3.5 GW between 2000 and 2011.[54]

Figure 6 suggests a relationship between the drop in the SUNIDX and the fall in the S&P GSCI. This correlation has raised concerns as to whether or not the two markets have a 'common trend' and are cointegrated. For instance, can solar PV flourish as natural gas prices continue to fall amid a glut of shale gas on the market? [55]

METHODOLOGICAL APPROACH

Prior to the shale gas boom, gas prices in the United States were nearly integrated and converged in different locations.[12–14] Establishing the interaction pattern between PV and natural gas is more challenging. One possible approach is to apply the Capital Asset Pricing Model (CAPM), where an investor's risk-return utility function determines equity portfolio selection.[56] Building on earlier work by Markowitz,[57] CAPM was independently developed by Sharpe (1964) and Lintner (1965).[58,59] The Sharpe-Lintner version of CAPM postulates a stable linear relationship between nondiversifiable risk and expected excess return. Versions of CAPM have been deployed to test for market integration.[60,61]

For the purpose of testing possible convergence patterns as outlined in this paper, however, a main shortcoming of the CAPM approach is that it looks at comparative statics and neglects the dynamic character of the market.[62] The CAPM model has been frequently criticized for its static assessment approach.[56,63] The one-period assessment approach fails to recognize key dimensions of risk.[63] In particular, in the context of the present study, the risk profiles of natural gas and PV markets show a marked difference across time; natural gas markets show relatively low capital risk but relatively high fuel price risk, while solar energy options face relatively high capital risk but low (or practically nonexistent) fuel price risk.

By focusing on the buyer of the service provided by both natural gas and PV using LCOE patterns over time, a multidimensional market perspective is introduced that is different from the investor's perspective of deploying capital. This multidimensional angle allows for the investigation of relative access to the market by the buyer of the service—a 'retail' or 'behind the market' consideration. This perspective introduces the need to apply a different methodological approach.

Li et al. (2014) applied the Phillips–Sul convergence test and time-varying parameter (Kalman filter) analysis to study the relationships among the United States, European, and Asian natural gas markets for evidence of convergence and integration from January 1997 to May 2011.[37] Cuddington and Wang (2006) applied autoregressive models to evaluate the degree of market integration in the U.S. natural gas market using daily spot prices at 76 locations from 1993 to 1997.[42] Using

TABLE 1 | U.S. Polysilicon, Wafer, Cell, and Module Prices

Description	2015 Q4	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Q4	2013 Q3
Polysilicon ($/kg)	14.93	15.91	16.65	19.23	20.72	21.12	21.73	20.36	17.52	17.17
Wafer ($/piece)	0.60	0.61	0.63	0.66	0.69	0.69	0.69	0.68	0.67	0.70
Cell ($/watt)	0.32	0.31	0.31	0.33	0.34	0.35	0.40	0.41	0.40	0.41
CSi modules ($/watt)	0.69	0.76	0.75	0.79	0.78	0.76	0.76	0.76	0.76	0.76
Thin-film modules ($/watt)	0.59	0.59	0.61	0.63	0.64	0.64	0.59	0.59	0.60	0.61

Notes: Polysilicon and photovoltaic (PV) components prices fell from the second quarter of 2014 to the second quarter of 2015. Significant polysilicon price reduction is primarily driven by increased inventory and seasonally weak demand. Weak market demand levels and pressure from buyers looking for low prices for modules continued over the same period, affecting wafer and cell prices in the second quarter of 2015, and is likely to continue in the first quarter of 2016. Data source: Bloomberg and GTM Research.[39]

time-varying parameter models and applying the Kalman filter estimation, King and Cuc (1996), Neumann et al. (2006), and Zachmann (2005) considered price convergence rather than integration.[13,64,65] On the other hand, de Menezes and Houllier (2016) adopted a time-varying fractional cointegration analysis using both spot and one-month ahead prices to investigate electricity price convergence and the effect of special events on the supply side on the pace of convergence.[35] We investigated evidence for convergence of the LCOE of PV and natural gas markets (based on changes in the solar module prices ($/Watt) and the Henry Hub-linked natural gas spot prices) from January 2010 to December 2015 using two techniques, namely, (1) the regression-based convergence tests proposed by Phillips and Sul (2007) and (2) Kalman filter estimations.[66] Table 2 lists all studies we are aware of that have investigated market integration and convergence costs of natural gas and/or solar power. Our methodological approach, therefore, resembles the approach applied by Phillips and Sul (2007), de Menezes and Houllier (2016), and Li et al. (2014), where market integration, price convergence, and natural gas spot prices were also evaluated.[35,37,66]

Phillips–Sul Econometric Convergence Test

The Phillips–Sul econometric convergence test is suitable for measuring the behavior of economies in transition toward a long-run growth path or individual transitions over time relative to some ‘common trend’ or representative variable.[66] The advantage of the formulation is that it allows for a stepwise clustering algorithm for finding convergence clusters in the data and does not rely on any assumptions of trend stationarity or stochastic nonstationarity in the data sample.[88] This aspect is particularly important for our analysis because many econometric time series variables, including natural gas and solar module prices, are nonstationary in levels.[89] To measure individual transition, using Ref 66 methodology, LCOE (price) (P) of the commodity form (natural gas or solar PV module) i, and in time period t, P_{it} can be expressed as:

$$P_{it} = g_{it} + \alpha_{it}, \tag{1}$$

where g_{it} is the systematic and permanent common components, and α_{it} represents transitory components.[f] The specification (1) may contain a mixture of both common and idiosyncratic components in the elements g_{it} and α_{it}. To separate common from idiosyncratic components, Ref 40 transforms (1) to a dynamic (time-varying) factor model (2):

$$P_{it} = \left(\frac{g_{it} + \alpha_{it}}{\mu_t}\right)\mu_t = \delta_{it}\mu_t, \text{for all } i \text{ and } t, \tag{2}$$

where μ_t is a single common component, and δ_{it} is a time-varying cross-section component element. For example, if μ_t represents a common trend component in the data, then δ_{it} measures the relative share in μ_t, of individual i and t. On the other hand, δ_{it} represents any specific variable that might influence the levelized costs (prices) of natural gas and solar PV, such as module, wafer, or cell prices for solar and national demand for natural gas.

TABLE 2 | List of Studies That Have Investigated Market Integration and Convergence Costs of Solar PV and Natural Gas Generation

	Econometric Modeling Focused	Energy Markets Focused
Market Integration	de Menezes and Houllier (2016),[35] Morvaj et al. (2016),[67] Wu et al. (2015),[68] Hirth (2013, 2015b),[69,70] Pudjianto et al. (2013),[71] Erdős (2012),[12] Nicolosi (2012),[72] Byrne et al. (2011),[73] Gowrisankaran et al. (2011),[74] Mills (2011),[75] Bunn and Gianfreda (2010),[22] Kalantzis and Milonas (2010),[21] Nitsch et al. (2010),[23] Neumann (2009),[14] Lamont (2008),[76] Neumann et al. (2006),[13] Rahman & Bouzguenda (1994),[77] Rahman (1990).[78]	Eryilmaz and Sergici (2016),[79] Feldman et al. (2014),[80] Hirth (2013),[69] Weiss et al. (2013),[10] Brown & Rowlands (2009),[81] Borenstein (2008),[82] Mills & Wiser (2012, 2014).[83,84]
Price convergence	Zhang and Broadstock (2016),[85] de Menezes and Houllier (2016),[35] Meng et al. (2013),[28] Mohammadi and Ram (2012),[29] Mills (2011),[75] Byrne et al. (2011),[73] Barassi et al. (2011),[27] Duro et al. (2011),[30] Cuddington and Wang (2010),[42] Le Pen and Sévi (2010),[31] Liddle (2009),[32] Panopoulou and Pantelidis (2009),[24] Aldy (2006),[26] Neumann et al. (2006),[13] Markandya et al. (2006),[34] Zachmann (2005),[65] Rahman & Bouzguenda (1994),[77] Ezcurra (2007a),[25] Ezcurra (2007b)[33]	Hirth et al. (2015),[86,87] Feldman et al. (2014),[80] Hirth (2013),[69] Mills & Wiser (2012, 2014)[84]

PV, photovoltaic.

To test the null hypothesis of convergence (long-run equilibrium) and show how the test works, Ref 66 proposed the following procedure:

$$H_o : \partial_i = \partial \,\text{and}\, \theta \geq 0,$$

against the alternative $H_A : \partial_i \neq \partial$ for all i or $\theta < 0$.

The cross-sectional variance ratios for the prices (H_1/H_t) is then constructed, where

$$H_t = \frac{1}{N}\sum_{i=1}^{N}(h_{it}-1)^2 \tag{3}$$

and

$$h_{it} = \frac{p_{it}}{N-1\sum_{i=1}^{N} p_{it}} = \frac{\partial_{it}}{N-1\sum_{i=1}^{N} \partial_{it}}, \tag{4}$$

h_{it} traces the transition path of the natural gas and PV module prices for country i in relation to the cross-sectional average at time t. Therefore, if δ_{it} converges to some ∂, then h_{it} converges to unity. In this regard, if the prices of the two commodities are converging, then H_t will converge to zero. Next, we estimate the regression in Eq. (5) and compute a conventional robust t-statistic for the coefficient $\hat{b}$ (i.e., using an estimate of the long-run variance of regression residuals):

$$\log\left(\frac{H_1}{H_t}\right) - 2\log L(t) = \hat{a} + \hat{b}, \tag{5}$$

for $t = [rT], [rT] + 1, \ldots, T$ with $r > 0$. H_1 is the cross-sectional variance in the first time period ($t = 1$). In this regression, we use the setting $L(t) = \log(t + 1)$, and the fitted coefficient of log$t$ is $b = 2\hat{\theta}$, where $\hat{\theta}$ is the estimate of θ in H_o. r is the fraction of data. Simulation experiments conducted by Ref 66 show that a small fraction of r of the time series data should be discarded in order to emphasize what happens as the sample size gets larger. Ref 66 recommends using an r value of 0.3 and explains Eq. (5) as follows: '*under convergence, log(H_1/H_t) diverges to* ∞, *either as* 2Log$L(t)$ *when* $\alpha = 0$ *or as* 2αlogt *when* $\alpha > 0$. *Thus, when the null hypothesis* H_0 *applies, the dependent variable diverges whether* $\alpha = 0$ *or* $\alpha > 0$. *Divergence of log(H_1/H_t) corresponds to* $H_t \to 0$ *as* $t \to \infty$. *Thus,* H_0 *is conveniently tested in terms of the weak inequality null* $\alpha \geq 0$. *Since* α *is a scalar, this null can be tested using a simple one-sided t test*' (p. 1789).

Performing the test with a heteroskedasticity and autocorrelation-consistent (HAC) standard error for the estimated coefficient, Eq. (5) is termed as a logt regression, and as the regression test includes the ratio of cross-sectional variance, Phillips and Sul (2007) refer to this as a 'conditional σ-convergence test.[66]

Club Convergence Algorithm

Should the null hypothesis of convergence be rejected, Ref 40 recommends using an algorithm based on repeated regression analysis to identify convergence subgroups. When convergence subgroups are present, Ref 66 and Ref 88 suggest that the evidence is most apparent in the final time series observations. The following four steps summarize the process of identifying convergence subgroups:

1. *Step 1*: *Last Observation Ordering*. The first step of the algorithm involves ordering of individuals in the panel according to the last observation. In the case of time series analysis, when there is substantial time series volatility, the ordering is performed according to some time series average of the last fraction of the sample. In a panel, the ordering is from the highest to the lowest.
2. *Step 2*: *Core Group formation*: Based on Step 1 above, select x highest prices and form a subgroup $P_{X,}$ with $x = 2, 3, \ldots N$. Next, calculate the convergence t-statistic, t_x, for sequential *logt* regressions based on the x highest members (Step 1) with $2 \leq x \leq N$. The core group size is chosen on the basis of the maximum of t-statistic x, with t-statistic $x > -1.65$.
3. *Step 3*: *Club Membership*: Following Step 2, select prices for membership in the core group (Step 2) by adding one at a time and include the new price (member) if the associated t-statistic is greater than zero. Ascertain that the club satisfies the criterion for convergence. After determining a club membership, perform a convergence t-test for the club to confirm that it is a convergence subgroup.
4. *Step 4* (*Recursion and Stopping*): Select members of the convergence club comprising the core subgroup to form a complement group. Thereafter, run the *logt* regression for this set of prices. If it converges, then these prices form a second club. Otherwise, repeat Steps 1–3 in order to reveal some subconvergent clusters. If convergence is found, there are two convergence subgroups in the panel. If not, repeat

Steps 2 and 3 to determine to see if there is a smaller convergence subgroup in the cluster.

This procedure has greater flexibility that makes it possible to identify cluster formations with all the possible formations, such as overall convergence, overall divergence, converging subgroups, and single diverging units.

Convergence and Long-Run Equilibrium

As discussed in *Introduction* section, time-varying factor representation provides a new way to model the long-run equilibrium of LCOEs of solar PV and natural gas systems and capture effects of different shocks in the energy market. Suppose that solar LCOE (S) and natural gas (G), i.e., *SolarLCOE (S) and GasLCOE(G)*, are integrated of order one. If for some coefficient θ, (*SolarLCOE(S)-GasLCOE(G)*) is integrated of order zero, then *SolarLCOE(S*) and *GasLCOE(G)* are said to be *cointegrated*. Cointegration methods are used for long-run analysis, while stationary time series methods are used for short-run dynamic behavior. Long-run common stochastic trends in the LCOE of PV and the natural gas markets are interpreted as a sign of market integration. Lack of evidence of cointegration shows that the market is not integrated. Such a supposition, however, might not be instructive if convergence in the market is moving toward integration during the selected sample period.

To test for cointegration using Johansen's framework to detect market integration, we used Eq. (2) to rewrite the difference between variable *SolarLCOE(S)* and *SolarLCOE(G)* as Eq. (6).

$$P_S - P_G = \left(\partial_{it} - \partial_{jt}\right)\mu_t. \qquad (6)$$

Typically, if μ_t is unit root nonstationary, and $\partial_{it} \neq \partial_{jt}$, then the two series P_S and P_G will not be cointegrated even when $\partial_{it} \neq \partial_{jt}$ converge to $\partial_,$ if the speed of convergence is not fast enough.

Time-Varying Parameter (Kalman Filter) Evaluation

Next, we employ the Kalman filter technique to estimate time-varying coefficients between each pair of the prices and investigate their relationship over time. We consider the following linear equation between the prices:

$$P_{j,\,t} = \beta_{1,t} P_{it} + \alpha_{ij} + \varepsilon_t, \qquad (7)$$

where $\beta_{1,t}$ is an indicator of the strength of the pricing relationship, α_{ij} captures transaction costs and quality differences, and ε_t is a random error term. When $\beta_{1,t}$ is closer to one, the two commodities are closer to achieving price convergence. A graphical examination of the temporal evolution of these coefficients makes it possible to test the convergence of the gas and solar module prices.

DATA DESCRIPTION AND EMPIRICAL ANALYSIS

The data used in calculating the LCOE of PV and natural gas generation systems employed in our analysis are from the Bloomberg databases. The weekly prices from January 2010 to December 2015 are averages for the Henry Hub-linked location (natural gas) and PV insights (solar PV module prices). In what follows, we model the LCOE prices to test for price convergence and market integration. The solar module data is derived from multiple poll contributions obtained by telephone interviews and are quoted in direct current (DC) (i.e., manufacturers rate their modules based on capacity to generate DC power). On the other hand, the natural gas prices represent a mixture of prices (i.e., long-term contract and spot cargoes), although these prices still exhibit spot price characteristics.

Because natural gas prices are delivered on long-term contracts, the volumes are fixed, through take-or-pay obligations, even if the prices are flexible to reflect changing market conditions, like in the case of PV modules. Hence, a comparison across the two LCOE series could shed some light on the nature of price responsiveness and market integration revealed through relative price changes. Figure 7 displays the variability of levelized costs of natural gas and PV generation systems from 2010 to 2015. We observe evidence of a sharp divergence in PV and natural gas prices from 2013 to 2015, which likely reflects the positive influence of policy, finance, and market changes in the solar industry and the significant impact of cheaper natural gas prices in the United States.

Determining LCOE to Characterize Natural Gas and PV Systems

The total balance of system (BOS) cost (C_{BOS}) of an installed PV system consists of inverter cost (C_{Inv}), fixed or indirect BOS cost (C_{FoI}), and area-related BOS cost (C_{Area}).[90] A breakdown of system cost (SC) consists of all the nonmodule cost items (total BOS cost) and module cost (C_{Mod}), as shown below.

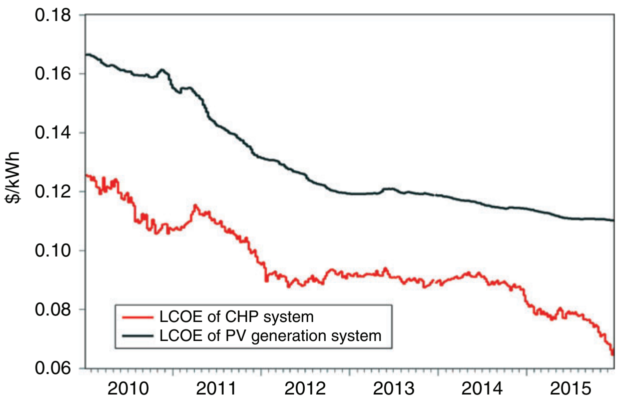

FIGURE 7 | Levelized cost of energy of natural gas-fired CHP and utility-scale PV generation systems. CHP, Combined Heat and Power System; PV, photovoltaic.

$$\begin{aligned}\text{System Cost} &= C_{Inv} + C_{FoI} + C_{Area} + C_{Mod} \\ &= C_{BOS} + C_{Mod} \end{aligned} \tag{8}$$

LCOE is a widely used meaningful metric to compare energy prices across different technologies, making it suitable for our analysis.[91] It is based on the concept that if all costs are assigned to 'every unit of energy produced (or saved) by the system over the analysis period, [they] will equal the total life-cycle cost (TLCC) when discounted back to the base year.'[90] Generally, an LCOE calculation is expressed as:

$$\text{LCOE} = \frac{\text{TLCC}}{\sum_{n=1}^{N} Q_e/(1+d)_n} = \frac{\sum_{n=0}^{N} C_e/(1+d)^n}{\sum_{n=1}^{N} Q_e/(1+d)^n}, \tag{9}$$

where, Q_n is the output of energy for the year n, C_e is the cost for year n, N denotes the period of analysis, and d refers to the discount rate. The technical performance and energy generation cost estimates for the PV system was calculated by running solar advisor model (SAM), a solar technology systems analysis tool developed by the National Renewable Energy Laboratory (NREL) and Sandia National Laboratory in partnership with the U.S. Department of Energy (DOE) Solar Energy Technologies Program (SETP).

TABLE 3 | Reference Information for Solar PV and Natural Gas Systems

Reference System	Solar PV	Natural Gas
System design, location, scale, and performance parameters		
Location	Sacramento, CA	
Capacity	1 MW	60 MW
Module efficiency	17.6%	48%
Inverter/system efficiency	96%	$12,000/MMBTU
Annual degradation	0.5%	
Tilt angle	Fixed, latitude: 33 degrees	
Module type	Standard	CHP[1]
Annual energy production	1,543,000 kWh	252,288,000 KW
Financial parameters and incentives		
Analysis period	25 years	40 years
Inflation rate	2.5%	2.5%
Real discount rate	8%	6%
Project term debt	40% of capital cost	
ITC	30%[2]	
Capital recovery factor	0.082	0.07
Fixed operating cost	$100/kW	$15/kWh
Capital cost	$5195/kW	$2000/kW
O&M	Inverter: $0.18/W	$0.004/kWh of energy produced
Total BOS	$1.5/W	
LCOE	12.95¢/kWh	9.5¢/kWh

BOS, total balance of system; CHP, Combined Heat and Power System; ITC, investment tax credit; LCOE, levelized cost of energy; PV, photovoltaic.

[1] Capacity Factors for Utility Scale Generators Primarily Using Fossil Fuels, January 2013-January 2016 (Table 6.7.A). Available at: https://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a; 2016. U.S. Energy Information Administration (EIA) (Accessed September 24, 2016).

[2] Energy Improvement and Extension Act of 2008: Summary of Provisions. Available at: http://www.eia.gov/oiaf/aeo/otheranalysis/aeo_2009analysispapers/eiea.html; 2009. U.S. Energy Information Administration (EIA) (Accessed July 1, 2016).

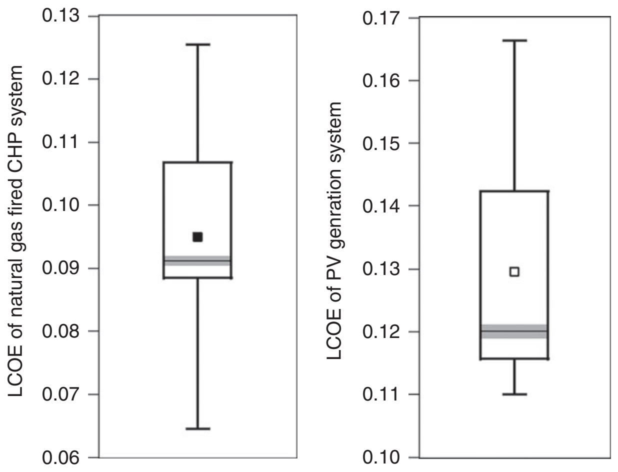

FIGURE 8 | LCOEs of CHP and PV systems. CHP, Combined Heat and Power System; LCOE, levelized cost of energy; PV, photovoltaic.

Two sets of reference inputs were used for PV module cost calculations: (1) case study location and performance parameters to calculate the actual energy output and (2) financing and incentives, SC inputs, and payment method to estimate the value of TLCC. We selected a 60-MW natural gas-fired combined cycle (CHP) plant and a 1-MW PV installation with fixed tilt angle at Sacramento, CA and specified all the system design, performance, and financing parameters (Table 3).

The PV reference system has a \$5195/kW capital cost and a \$1.5/W total BOS cost, while the natural gas system has \$2000/kW capital cost. The module type is standard, with an efficiency of 17.6% and inverter efficiency of 96%. Using these inputs, SAM calculates the LCOE of 12.95¢/kWh (i.e., energy cost to the manufacturer) and an annual energy production of 1,543,000 kWh. We use this annual energy production calculated from SAM and other system specifications shown in Table 3 to estimate the LCOE for PV and natural gas systems for the period of the study (see Figure 8). Sensitivity analysis for several input variables, including discount rate, project lifetime/analysis period, and cost of capital on solar PV, is presented in Figure 9.

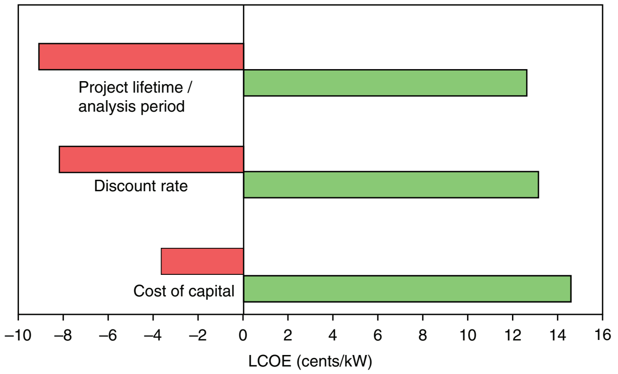

FIGURE 9 | Sensitivity analysis of PV system model parameters. Sensitivity analysis was conducted by adjusting the input variables up and down +/−10%.

Price Convergence Test

In this section, we discuss the main results of convergence tests. The papers by Cuddington and Wang (2010), Neumann et al. (2006), and Zachmann (2005), which show how to apply autoregressive models to evaluate price convergence and market integration, and Weiss et al. (2013), which analyzes interactions between natural gas and renewable energy markets, were of particular interest for this purpose.

Prior to performing the Phillips–Sul convergence test, we determined the relative transition parameters of each LCOE series (by filtering the data and removing the business cycle component) because of our interest in the long-run market characteristic, as defined by Eq. (5) and shown in Figure 10. The transition paths of the spot prices represent the evolution of each convergence club relative to the cross-section average. If we consider the logs of the indices of the two commodities, we observe that they move together over the full period as shown in the separate transition analysis between the S&P GSCI and the SUNIDX indices in Figure 11. This suggests strong evidence of a complementary relationship between the two energy markets.

The large drop of the logs of the two prices between 2008 and 2009 may reveal a more significant impact of the economic financial crisis. During 2008–2012, a similar pattern of price movement for S&P GSCI and SUNIDX emerged, reflecting the period of sluggish economic recovery from the impact of the global financial crisis in the United States. The hypothesis of the test is:

$$\begin{aligned} H_o &: \leq 0 \\ H_A &: > 0. \end{aligned} \tag{10}$$

Before preforming the convergence test, we applied the Hodrick–Prescott filter with a smoothing parameter (λ) of 270,400 to the LCOE series in order to take off the components associated with the business cycle and concentrate on the long-run behavior.[g] The estimated equation for the overall test is:

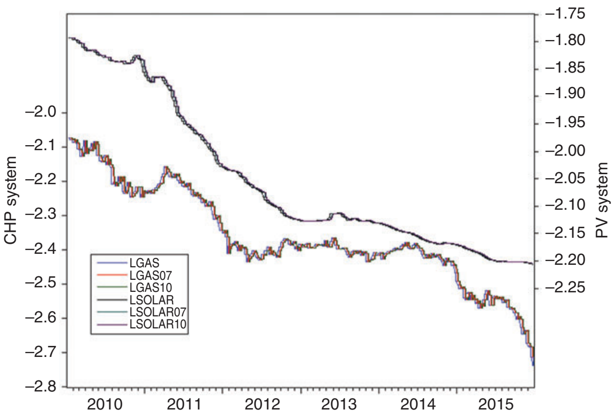

FIGURE 10 | Relative transition paths (club convergence).

$$\log\left(\frac{H_1}{H_t}\right) - 2\log L(t) = 0.394 logt - 1.002. \qquad (11)$$

The *t*-statistic is −0.689, probability is 0.973, and 1% critical value for the *t*-test is approximately −3.964; hence, the null hypothesis is rejected at that level (see Table 4).

However, rejection of the overall convergence does not mean convergence is not present in the other series. Next, we follow the steps outlined in *Club Convergence Algorithm* section and display our results in Table 5. Using LogGas prices, we performed a club convergence test by adding the LogSolar prices. The *t*-statistics are 7.479 and 6.739 for *x* = [1,2] and [1,2,3], respectively, which are much larger than the critical values. Based on these results, we conclude that there is some evidence of convergence (very high *t*-stats relative to the critical values).

The solar module and the Henry Hub-linked gas prices appear to represent markets of their own. The respective markets appear to be driven by different mechanisms, and a price differential in one market does not necessarily result in changes in the other market. For instance, the drop in the solar module prices between 2010 and 2015 occurred during the same period of low natural gas prices, but this period is consistent with the timing of the shale gas production impacts. The convergence tests suggest that the natural gas and solar markets are experiencing major structural changes. To examine the time-varying relationships, we employ the Kalman filter to determine the state estimates. Augmented Dickey–Fuller (ADF) test statistic show that both the unit root and the ratio of levelized costs of natural gas and PV generation are nonstationary in levels, even around a trend; the *t*-statistic is too low (−0.689), and the estimated probability for the coefficient to zero is extremely high (97.3%). However, the series is stationary in the first difference (*t*-statistic is −38.95). The results of the estimates and residuals are presented in the Appendices S1–S5, Supporting information. The result of the Johansen cointegration tests (i.e., Trace test) indicates no cointegration at the 0.05 level in the prices.

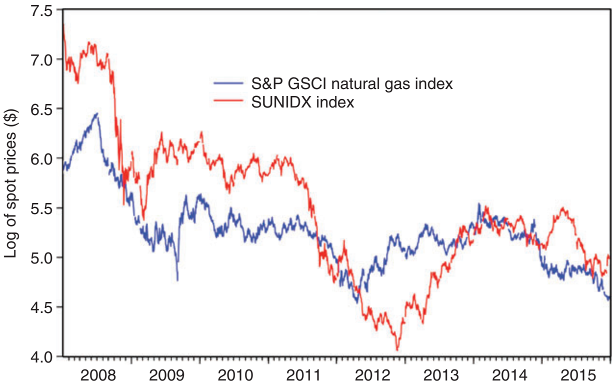

FIGURE 11 | Natural gas and SUNIDX indices log spot prices.

The combined results of our Kalman filter and convergence tests suggest that the natural gas and the solar module prices are separate and distinct markets. These markets are not integrated. This distinction is amplified by supply–demand balance and market dynamics, especially recent developments in shale gas and substantial investments in renewable energy.

MAINTAINING A GOLDILOCKS RANGE OF NATURAL GAS AND PV PRICES

Expansion in shale gas development in the United States has signaled a transition from coal to natural gas for power generation. This growth has been driven by the evolving regulatory regime, especially in open gas market development, technological development, and by the steady increase in efficiency of gas turbines and combined cycles.[92] The ability of the United States to sustain this transformation with respect to natural gas supply, however, depends on the expectation that future average gas prices will remain low. Concerns about price volatility and supply–demand imbalances in the gas market, nevertheless, abound despite the recent shale boom. Unlike the solar market, volatility was more widespread in the natural gas market from 2010 to 2015 (Figure 12). Moreover, commodity futures and options markets predict significant price volatility

TABLE 4 | Unit Root Test in Regression Equation (11); Dependent Variable: D(LGASDivSOLAR)

	ADF Test			
Variable	Coefficient	*SE*	*t*-Statistic	Probability
D(LGASDivSOLAR	−0.001900	0.002756	−0.68918	0.4908
C	−0.000407	0.000889	−0.45764	0.6473
@TREND	−4.11E-07	3.24E-07	−1.270610	0.2041
R^2 = 0.001283		Test critical values:		
SE of regression = 0.005715		*t*-Statistic = −0.689181	Prob.: 0.9729	
Log likelihood = 5803.66		1% level: = −3.964		
F-Statistic = 0.99335		5% level: = −3.427		
Prob(*F*-statistic) = 0.37057		10% level = −3.128		

ADF, Augmented Dickey–Fuller test; *SE*, standard error.

over the next decade.[5] Price volatility, characterized by relative deviations around the average gas price, is inevitable in a competitive gas market such as in the United States. When the industry operates close to full capacity, small changes in supply and demand may cause strong market pressures and substantial price volatility. This was evident in late 2000 and early 2003 when gas supply–demand imbalance led to a price surge.[93]

Meanwhile, renewable energy options like solar PV and natural gas both play important roles in preserving electric grid reliability and together these two energy forms account for most of new electricity generation capacity additions in 2016. Weiss et al. (2013) analyzed potential synergies in partnering natural gas and renewables in the ERCOT and concluded that in the short term, because renewable sources such as wind and solar energy have no fuel cost compared to conventional energy sources (i.e., oil, natural gas and coal), a lower natural gas price would unlikely crowd-out renewables.[10] This is consistent with the Goldilocks principle that just the right price for natural gas will lead to the highest level of solar output. However, due to the capital-intensive nature of large-scale solar projects, a longer lag in the planning, financing, and approval process for utility-scale solar projects affect when they come online on the grid. Also, solar producers may take advantage of high gas prices and respond by delaying the planning, financing, and development of large-scale solar projects 3–5 years later. This was evident from high solar installations from 2007 to 2012 following all-time high gas prices from 2003 to 2008.[94]

Regulatory support, rate of return guarantees on infrastructure-scale solar investment, and permanent ITC policy and finance instruments will likely result in an increased share of solar energy in the U.S. power generation mix, potentially resulting in multiple hedging benefits for natural gas price volatility as solar PV projects that meet requirements for renewable portfolio standards (RPSs) typically have long-term PPAs, are not subject to future cost uncertainty, and have little or no fuel costs.[50,55,68,79] Moreover, because of their modularity, PV systems provide valuable flexibility to deployment timelines of new capacity and, therefore, can progressively hedge against risks associated with rising natural gas prices and future policy uncertainty.[48] On the other hand, the fast-ramping ability of natural gas

TABLE 5 | Club Convergence Tests

Last T Order	Name	Core Group Formations	Critical Values
1	lnGas_lnSolar_1	Base	4.51E-05
2	lnGas_lnSolar_2	7.479	0.286
3	lnGas_lnSolar_3	6.739	0.575

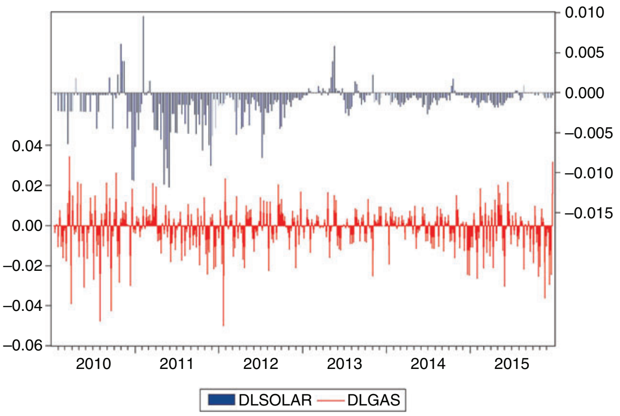

FIGURE 12 | Price volatility in the PV and natural gas markets. PV, photovoltaic.

systems makes them ideal for complementing demand with variable output from solar PV generators. No technical difficulties have been linked to integrating larger amounts of solar PV while fully maintaining reliability.[50] Volatility in the price of natural gas, decline in PV system and module costs, demand-side management policies, and an uncertain ITC policy regime, however, will continue to cause significant structural market changes in the composition of new gas and renewable generation facilities in the short run. In the long run, improving the economics of gas-fired power plants will yield a cost-competitive advantage as options for new capacity additions, and this might affect the high penetration of renewable capacity, principally due to high upfront cost differentials.[43]

End-use solar energy will continue to expand as module prices fall further. This will improve PV's competitiveness with natural gas on a levelized cost basis.[48] In the short run, a low natural gas price benefits renewables by reducing the overall levelized costs of energy, thus deepening further complementarity opportunities between utility-scale PV and natural gas from a least-cost perspective and operating cost viability prospect. The two markets can exhibit complementarity at multiple levels, ranging from tightly coupled hybrid deployment to more loosely integrated systems.[48,55] Such deployment could further benefit from utility business model innovation and future electric power market designs. As a result, low gas prices could benefit solar energy growth by making renewables a hybrid gas-renewable system and, therefore, lowering overall generation cost (compared to a solar-only strategy). In the long run, the effect of low natural gas prices on solar energy growth will depend largely on the positioning of finance, market, and policy transformations in the U.S. power market to deliver a sustainable energy future, such as resource distribution, fuel and capital cost, load characteristics, dispatching system, carbon impact, and relevant environmental regulations.

The increased shale production capacity and the positive externalities inherent in cheap natural gas prices, therefore, have mixed effects on renewables. Our analysis suggest that the overall crowding-out effect of lower natural gas prices on the market share of renewables, although a dominant industry concern, is not that large in the post-shale boom period. In this context, to avoid further 'crowding-out,' policy, finance, and market interventions are needed in different configurations to support, expand, and strengthen those instruments that extend synergistic opportunities between solar energy and natural gas.

CONCLUSION

Using the Phillips–Sul econometric convergence test, this paper examined whether solar PV module and gas prices in the United States have converged since the beginning of the shale gas boom in 2008. We investigated the dynamics of supply–demand balance and market dynamics on solar and natural gas prices. Our analysis found that a cointegration test is not suitable for this task. We also found that the segmentation of these markets could be attributed to a combination of policy, finance, and energy market factors, such as shale gas developments, a history of gas-on-solar pricing, and growing investments in renewable energy sources. Increased U.S. shale production is already having a major impact on the power generation sector, and this is likely to expand in the future to other sectors, including transportation, manufacturing, and chemicals. The potential of increasing the avoided CO_2 emissions due to coal-to-gas fuel switching in the power sector is sizable and rapidly expanding. With further growth in shale gas extraction forecasted until 2035, natural gas will continue to assert itself as a bridge fuel to a low-carbon, renewable energy-based economy owing to its lower emissions profile.[7]

Without maintaining technological and institutional energy systems' carbon-based 'lock-in,' the use of policy tools to establish the price of natural gas into a Goldilocks range that facilitates continued growth of installed solar capacity in the future could accelerate further synergistic benefits of renewables and natural gas. The manufacturing sectors that rely on natural gas feedstock or can substitute gas for other fuels have seen their production costs fall, and this trend will likely continue during the shale boom period. Natural gas production has also remarkably expanded the U.S. resource base because low prices have forced gas producers to search for innovative mechanisms to further drive down production costs.

Our analysis suggests that natural gas and solar module prices are neither converging nor integrated nationally. However, some level of integration could exist at regional, state, or city levels. In this regard, additional research is required at the local level, especially in areas that have witnessed increased expansion in shale production (such as Pennsylvania, Gulf of Mexico, Texas, West Virginia, and Oklahoma). Finally, an improvement in laws and policies

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governing market competitiveness and 'direct democracy' pathways by which local stakeholders can influence the narrative of policies would also facilitate greater participation in these markets, create price stability, and reduce market volatility.

NOMENCLATURE

g_{it} = Systematic and permanent common components
α_{it} = Transitory components
δ_{it} = Time-varying cross-section component element
μ_t = Single common component
\$/kg = Solar PV Polysilicon spot price
\$/piece = Solar PV wafer spot price
\$/watt = Solar PV module spot price
ADF = Augmented Dickey–Fuller test
Bcf/d = Billion cubic feet per day natural gas
BOS = Total balance of system
CAPM = Capital asset pricing model
C_{Area} = Area-related BOS cost
C_{BOS} = Cost of BOS of installed PV system
C_{FoI} = Fixed or indirect BOS cost
CHP = combined heat and power system (or Cogeneration)
C_{Inv} = Inverter cost
C_{Mod} = Module cost
CO_2 = Carbon dioxide emissions
EIA = Energy information administration
ERCOT = Electric Reliability Council of Texas
GTM = Greentech Media
HAC = Heteroskedasticity and autocorrelation-consistent covariance estimation
ITC = Investment tax credit
LCOE = Levelized cost of energy
LOP = Law of one price
MMBtu = One million British thermal units (BTU)
MW = Megawatt
$P_{i,t}$ = Commodity price (natural gas or solar PV module) *i* and in time period *t*.
PPAs = Power purchase agreements
PSO = Power systems optimizer
REV = Reforming the energy vision
S&G GSCI = S&P Goldman Sachs Commodity Index
SAM = Solar advisor model
SC = Sum of all nonmodule cost items (i.e., Total BOS cost) and module cost (i.e., $C_{Inv} + C_{FoI} + C_{Area} + C_{Mod} = C_{BOS} + C_{Mod}$)
SEIA = Solar Energy Industries Association
SETP = The U.S. Department of Energy Laboratory (DOE) Solar Energy Technologies Program
Solar PV = Solar photovoltaics
SUNIDX = MAC Global Solar Energy Index for the Guggenheim Solar Exchange Traded Funds
TLCC = Total life cycle cost

SI UNITS

1 BTU = 0.000293071 kWh = 1.05506 kJ
1 kWh = 1000 Watt-hours (or 3.6 MJ)
1 tonne = 6.84 Barrels
1 barrel/day for 1 year ≈ 50 tonnes
1 barrels of oil equivalent (BOE) = 5.8 MBtu
1 Cubic Feet = 1020 Btu

NOTES

[a] In this paper, 'utility-scale' solar projects include concentrating solar power (CSP) and PV projects of system capacity 5 MW or larger.

[b] Econometric analysis conducted by SEIA/GTM Research shows that 40% of the 16.6 GW utility pipeline in development is primarily due to cost reductions in relation to fossil fuel alternatives.[39]

[c] Dry natural gas production is the process of producing consumer-grade natural gas. It equals marketed production less extraction loss.

[d] The inception of the MAC Solar Index was March 31, 2008 with a base of 1000. The historical data prior to the index inception, i.e., from March 31, 2005 to March 3, 2008, is backcasted simulated data using the same index methodology that is used in defining the index going forward. For more information, see www.MACSolarIndex.com.

[e] All information for S&P GSCI natural gas index spot prices prior to its launch date is backtested based on the methodology that was in effect on the launch date. Backtested performance, which is hypothetical and not actual performance, is subject to inherent limitations because it reflects the application of an index methodology and the selection of index constituents in hindsight. No theoretical approach can take into account all the factors in the markets in general and the impact of decisions that might have been made during the actual operation of an index. Actual returns may differ from, and be lower than, backtested returns. For more information: http://us.spindices.com/indices/commodities/sp-gsci-natural-gas.

[f] Nonstationary series can be decomposed into permanent (or 'trend') and transitory (or 'cycle') components.

[g] For the smoothing parameter, λ, we used the default value in Eviews 8.1, (i.e., λ = 270,400) to obtain a smooth estimate of the long-term trend components in the objective.

FURTHER READING

Hefley EW, Yongsheng W, eds. *Economics of Unconventional Shale Gas Development: Case Studies and Impacts*. New York: Springer, 2015. ISBN: 978-3-319-11498-9.

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