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The Cost of Renewable Power Integration and the Transition to Low Carbon Emissions for Japan's Energy Industry

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Abstract
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Keywords
Emission reduction, Consumer Cost Tolerances, Paris Accords, Renewable Generation

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Business

The Cost of Renewable Power Integration and the Transition to Low Carbon Emissions for Japan's Energy Industry

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ABSTRACT

An earthquake on March 11, 2011 caused catastrophic damage to Eastern Japan's people, infrastructure and energy markets. This event signified the need for dramatic change towards sustainable energy. The recent Paris Accords on climate change has provided a framework for sustainability development towards CO_2 emission reductions. Therefore, the experiment in this paper models the proposed increase to ~23 percent renewable generation as well as modest decreases in fossil fuel generation relative to generation demand and emissions reductions. The results of this paper will demonstrate that there is a ~56 percent chance under randomized input scenarios that cost increases remain within consumer tolerance levels. Further compounding this analysis, this probability falls to ~34 percent when considering targeted emissions levels. The incidence of these probabilities can be dramatically impacted by an overall decrease in the commodity inputs for fuel prices and an increase in costs levied against carbon emissions.

Key Phrases: Emission reduction, Consumer Cost Tolerances, Paris Accords, Renewable Generation

INTRODUCTION

Fukushima Daiichi Nuclear Power Station Disaster

On March 11, 2011, there was a 9.0 magnitude earthquake off the coast of Tohoku, Japan that created a 13 meter tall tsunami. This tsunami bypassed the ten meter containment wall surrounding the Tokyo Electric Power Company (TEPCO) Fukushima-Daiichi nuclear power plant (NPP). The water breached the radiation containment of a number of nuclear reactors and caused two catastrophic explosions due to a coolant system failure. The explosion of these reactors leaked radiation into surrounding areas and the site of the explosion still remains heavily irradiated. The earthquake and resulting tsunami caused over 15,000 deaths and collapsed over 125,000 buildings. The World Bank has since estimated the total cost to be approximately $235bn (Vivoda 2014, 1).

Beyond the immediate loss of life and infrastructure throughout Eastern Japan, there were wide-reaching implications for Japan's energy markets. A vast majority of the thermal and nuclear plants were damaged by the tsunami which caused rolling power outages for ~4.4 million people over the following 12 months. Six petrochemical refineries suffered serious damage, several coal unloading facilities collapsed, and the Minato LNG terminal at Sendai which provides local gas distribution services to over 400,000 households was restricted (Vivoda 2014, 1). Due to regional transmission incompatibilities from their divided 50Hz/60Hz system, Japan faced a number of serious problems in finding temporary sources of generation to meet demand. Peak demand in 2011 was met through a series of comprehensive electricity conservation measures. Electricity production dropped ~22 percent in 2012 and the overweighted thermal generation increased costs which resulted in a trade deficit in excess of $100bn in 2012 (Vivoda 2014, 2).

In reference to the global impact this event had, Germany announced in late May of 2011 their intent to phase out all nuclear generation capacity by 2022 in favor of renewable generation with a long-term goal of 50 percent generation from renewable sources. This phase-in of renewables has led to an approximate 20 percent increase in prices (World Nuclear Association, 2015). This price increase covers the current increase in cost due to a greater emphasis on renewables generation. Additionally, a portion of these funds is required to be set aside for future renewable project development. (World Nuclear Association, 2015)

Japanese Power Industry Overview

Despite all of these challenges, the most impactful change in Japan's energy policy was that Japan decommissioned all of its nuclear power plants in the wake of the disaster. Japan has 11 regional monopolies that control the generation of electricity and the transmission and distribution of that electricity throughout Japan. These utilities have a total of over 334.8GW of production capacity that span fuel sources such as nuclear, hydroelectric, coal, natural gas, oil, and other renewables (BMI, 2016a). These companies are regulated by the Ministry of International Trade and Industry (MITI) and the Ministry of Economy, Trade and Industry (METI), which set prices and determine operating protocol (Vivoda 2014, 13). Nine of Japan's eleven monopolies, including one purely wholesale, operate nuclear power plants which accounted for approximately 25-30 percent of Japan's overall energy production before Fukushima. Since the disaster, only the Sendai Plant No. 1 Nuclear Reactor of the Kyushu Electric Power Company with a rated capacity of 5MW has been reinstated since August 2015 (Jiji, 2015). As it stands, the largest sources of energy production, as a percentage of total terawatt hours (TWh) produced, in Japan are Natural Gas (36 percent), Coal (28 percent) and Oil (17 percent). Historically, there has been much more variation in the prices of these commodities relative to the normalized long-run costs of nuclear and renewable sources that incur large initial costs and then can run effectively for a number of years (BMI, 2016d). A complete breakdown of relative generation by asset class in 2015 can be found in **Exhibit 1**.

Due to the isolated nature of Japan's energy grid, their government has put into effect a number of policies that look to increase their energy independence and avoid future disasters like Fukushima. The available renewable energy sources in Japan are solar, wind (onshore and offshore), hydroelectric (large and small), and limited biomass and geothermal. Japan's utilities have been historically suspicious of renewable energy sources in that they are generally developed by independent power producers (IPPs). The reluctance to adopt wind technology despite its high potential capacity (~190GW), comes from deficiencies in Japan's transmission system (Vivoda 2014, 13). Therefore, due to the complexity of these projects, utilities have historically advocated regulators impose artificial impediments to wind energy development, such as heightened levels of permitting and regulatory approval times. Recently, Japan's government has created incentives for these utilities to develop their own renewable energy sources, including wind, in the form of Feed-In-Tariffs (FITs), which set above-market prices to subsidize renewable energy development. Solar generation has been easiest to integrate without upgrades to their regional transmission system and thus has been the most developed with nearly 10W of capacity installed in 2015 (Beetz, 2016).

The current amount of total potential generation from all sources is 60.5 percent thermal generation and 39.5 percent non-thermal. The mismatch between these capacity numbers and the relative generation numbers from **Exhibit 1** is attributable to the fact that certain types of generating technology are capable of producing electricity for different amounts of time throughout the year. For thermal generation sources, this can be over 50 percent and for renewable source, this lies closer to 20 percent (EIA, 2015a). A full breakdown of potential generation capacity by asset source can be seen in **Exhibit 2**.

At the end of 2015, the representatives of 195 countries met in Paris to develop a comprehensive, multi-national initiative to reduce global carbon emissions. While there have been a number of attempts at such agreements in the past, none have led to any meaningful and sustained reductions. However, given the Fukushima Daiichi disaster and the ensuing reliance on fossil fuel generating technologies, energy independence and sustainability is of paramount importance to Japan. Each country in attendance submitted an Intended Nationally Determined Contribution (INDC), submitted to the United Nations Framework Convention on Climate Change (UNFCCC) which outlines their plan to reduce carbon emissions. In short, Japan has committed to a 25.4 percent reduction in emissions by 2030 relative to fiscal year 2005. This result takes the pro-rated emissions decrease by 2025 of 16.9% in order to remain close to the projected energy demand range. They also submitted the following approximation for their breakdown by generating source (UNFCCC, 2015). The proposed INDC generation by source can be found in **Exhibit 3**. This maintains nearly comparable levels of generation for coal and natural gas, almost completely eliminates oil-fired generation, increases nuclear generation to pre-Fukushima levels, and increases renewables generation by ~250 percent (UNFCCC, 2015).

RESEARCH QUESTION

Weighing all of these recent developments and the relatively more favorable environment they have created for renewable energy developments, the process of integrating large-scale renewable generation sources into Japan's long-term production profile is critical to the future of Japan's energy security. Recent studies have only discussed the viability of specific renewables in meeting Japan's future energy demand. The specific question that will be addressed in this paper is the total cost of implementing a range of possible generation paths and what governmental policies, especially carbon emission costs, and macroeconomic conditions, especially fuel prices, would be required to facilitate a low-carbon generation mix. The simulation described in this paper encompasses cases that will cover a very broad set of generation paths. The goal will be to see under what scenarios the Japanese energy system can achieve the emissions reductions under INDC submission to the UNFCCC while maintaining the total cost of the system within tolerable ranges for Japanese consumers.

SIGNIFICANCE

There are a number of different parties that would be interested in the results of this research. On the whole, this audience can be separated into three different groups: *policymakers*, *energy investors*, and *scholarly researchers*.

Policymakers

Policymakers in Japan, abroad, and those indirectly connected through organizations like the OECD, are still dealing with the consequences of Fukushima Daiichi. For example, as stated above, Germany has shut down all of their nuclear generation plants in response to the Fukushima disaster. Japan is now currently considering the possibility of re-commissioning a number of their nuclear plants. This analysis regarding how to incorporate renewables, plus nuclear, into previously nuclear-heavy generation states would be directly relevant. As governments are beholden to their constituents, they will look for information relating to how this will impact consumers on a retail and industrial scale from a cost perspective, the implications for macroeconomic growth, and how this would impact their ability to meet targets for reduced emission standards set by multinational initiatives.

Energy Investors

Directly related to the interest exhibited by policymakers, energy policy drives energy project economics which in turn drives investor interest. This paper will outline the viability of renewable developments and their greater economic impact, and will give insights into Japanese energy market policy and potential governmental responses. As stated above, there is little research regarding the financial viability for different renewable mixes and how that impacts regulation regarding prices and incentives for asset development. These readers would be looking for information that would inform them as to the long-term impact of renewable energy development on Japan's energy market.

Scholarly Researchers

Finally, there are scholarly researchers who would be interested in this research. Performing a total cost analysis of integrating renewable generation, including oil and gas and nuclear, would provide a more holistic view of the future of energy markets in Japan. Focusing on the total cost and the profile of investments will add value to this field of analyses. As stated above, the existing pre-Fukushima scenario-based research only analyzes Japan's generation profile from the perspective of emissions reductions or generation totals with no direct emphasis on the cost to the companies and consumers, the changing dynamic of willingness to pay for low-carbon sources, and a more favorable regulatory environment. This paper will discuss these areas and look to tie together the previously fragmented research in this market. Such an analysis will further provide lessons that comparable countries could use as a model for their own decisions regarding energy policy and lay the groundwork for further cross-national research.

LITERATURE REVIEW

The most common research theme on the topic of Japanese energy surrounds the idea of energy stability. This encompasses not only the idea of sustainability but flexibility and the ability to respond to supply shocks like that of Fukushima Daiichi. Since this disaster occurred somewhat recently, a large portion of the research comes from before the meltdown. Research is roughly separable into three major segments: *policy research*, *cost analysis* and *other areas*.

Policy Research

For policy considerations, most existing research analyzes energy market policy in Japan pre-Fukushima. Japan's minimal domestic resources for energy generation have underscored historical volatility and a tendency towards fossil fuel-based generation. In 2007, the primary energy supply was weighted 47 percent towards oil and 21 percent towards coal across their major reporting sectors: industrial, transportation, commercial, and residential. As such, their CO_2 emissions had grown to approximately 15 percent above 1990 levels before nuclear development increased around 2008 (Tatsujiro and Takase, 2011). Before Fukushima, there was the Kyoto Protocol which provided a rough outline for "de-carbonization" and certain emissions milestones Japan sought to achieve along a timeline. A key provision of the Kyoto protocol included carbon emissions of no more than 2.3 percent above 1990 levels and the continued heavy use of nuclear technology. This was supplemented by the Fukuda Vision which included integrating emission trading schemes (ETS) and reducing greenhouse gas (GHG) emissions to 75 percent of 1990 levels by 2020 (Tatsujiro and Takase, 2011). Additionally, Japan implemented the Renewable Portfolio Standards (RPS) Law that required utilities to provide 1.35 percent of all electricity demand with "new energy" source: solar, wind, hydroelectric, biomass. Furthermore, this research performs various scenario analysis that, "show that drastic CO_2 emissions can be achieved by assuming maximum efficiency savings and very aggressive renewable energy deployment, even with a nuclear phase-out policy…to just over half of current levels by 2030 (Tatsujiro and Takase, 2011).” However, they model only one source of renewable energy, fail to calculate projected costs to the consumer and assume an aggressive nuclear policy that includes extending the life of existing NPPs.

Immediately in the wake of Fukushima, there were a number of different plans put in place that redesigned the projections set forth by the Kyoto Protocol. The most prevalent of these is the Basic Energy Plan (BEP) that created a number of options for implementing processes to effectively manage future energy supply shocks and the new course of the power industry (Tatsujiro and Takase, 2011). One article recommends that due to the troubled nature with the transmission and distribution grid, as mentioned above, it might be more efficient to separate (de-integrate) the monopolies such that there are regional transmission organizations (RTOs) that purchase wholesale energy and act as the retailer. This is facilitated by three amendments to the Electricity Business Act established in the early 2000s that make it easier for IPPs to enter wholesale power markets and expand retail liberalization for large users. This research illustrated that, “the current operation for transmission may belong to the optimal size” for vertical de-integration, making competitive wholesale generation competitive (Tatsujiro and Takase, 2011).

Cost Analysis Research

The research on cost analysis for integrating renewables post-Fukushima is limited in scope but provides a number of useful reference points. Most of these analyses are highly technical and apply levelized cost of energy (LCOE) analyses to a number of different scenarios. This first study used scenario analysis and the consideration of four major variables including: the ongoing debate for the future of Japan’s energy policy post-Fukushima, the current socio-economic and socio-political environment of contemporary Japan, the estimated potential for renewable energy sources, and technological constraints for the expansion of renewable energy. While this study does in fact incorporate multiple renewables while focusing primarily on the impact to GHG emissions, it only focuses on solar generation supplanting some fossil fuel generation over a 20 year development horizon from a construction standpoint, not necessarily cost (Goto et. al., 2013). Furthermore, this study fails to identify which scenarios will likely be most appropriate given considerations of costs to a consumer and other exogenous variables that would impact the viability of integrating intermittent generation sources, like carbon costs.

This piece was supplemented by the results of another study that illustrated there was a much higher incremental willingness to pay (~8 percent) per MWh of clean production among Japanese respondents than individuals in the United States (Friedman et. al., 2015). Respondents in both Japan and the United States showed an equal lack of enthusiasm for the increased scale of nuclear energy production and thus a demand curve that aligns with the increased cost of renewable energy and increased development, similar to policies in Germany that include a surplus payment for utilities to allocate for future renewables development.

These perspectives on the viability of renewables were enhanced by another piece of work that incorporates the idea of energy storage to normalize supply over time, a notoriously difficult obstacle for renewable energy. This was a cost analysis piece dealing with the feasibility of incorporating hydrogen storage methods into Japan's energy grid. Energy storage promotes flexibility and can help normalize energy supply shocks but this analysis was on a drastically reduced scale referencing a 1MW solar plant outside of Tokyo (Fujii et. al., 2015).

Other Research Areas

There are other isolated areas of research that dealt with certain types of renewable energy such as geothermal and hydroelectric. Additionally, there have been many analyses by inter-governmental organizations such as the Organization for Economic Co-operation and Development (OECD) and the Nuclear Energy Agency (NEA) discussing the impact of Fukushima on Asian energy markets. There was a geothermal report titled *Life Cycle Employment Effect of Geothermal Power Generation Using an Extended Input-Output Model: The Case of Japan*. This dealt with the direct and indirect impacts of introducing geothermal sources into Japan's generation mix. These include cost to the consumer and macroeconomic augmentations such as increased employment and potential barriers to entry (Hienuki et. al., 2015). The OECD/NEA report is entitled *The Fukushima Daiichi Nuclear Power Plant Accident: OECD/NEA Nuclear Safety Response and Lessons Learnt*. This focuses mostly on the international response of OECD and NEA member states to the Japanese disaster, focusing on enhancing existing regulatory infrastructure, adding new protocols for accident management, as well as a review of a number of legal frameworks and liabilities. The report touted the merits of standardization and coordination during nuclear crisis to mitigate consequences.

INITIAL HYPOTHESIS

By incorporating observations from the works cited in the literature review above, the initial hypothesis of this paper is that Japan's energy market can efficiently manage a transition to a low carbon generation system with an increased emphasis on renewable technologies, while managing the cost of the system to be within Japanese consumers' willingness to pay. This will be achieved through aggressive carbon emission cost policies, selectively managing the decrease in the current thermal generation base and increasing the installed renewable generation base.

METHODOLOGY

In the study of how to incorporate renewable energy investment into the post-Fukushima energy profile for Japan, there are generally two areas of data that will be needed. The two major areas are *macroeconomic projections* and *total cost analysis*. There are a number of different sources from which information regarding these two areas can either be found or derived. The majority of the information will be aggregated and analyzed in Microsoft Excel.

Macroeconomic Projections

Macroeconomic considerations are an extremely important base for any study in the energy space, since there are a number of different factors that would impact a country's projected energy need. These considerations will encompass some easily observable information such as population growth, unemployment rates, single/multi-family home construction rates, industry growth rates, and historic electricity sales. Fortunately, this will also be the most easily accessible information. A number of different sources provide the historical information in these areas such as individual firm analyst reports published by research companies like BMI Research. This paper will rely on external projections for future consumption instead of developing its own and use historical commodity price movements to guide estimates of future prices.

Total Cost Analysis

The next area of analysis relates to the range of potential generation paths outlined above. Using the macroeconomic information outlined above as well as the industry-wide projections for energy consumption, it will be a function of matching the cost and generation profile to meet demand. This will also incorporate knowledge of the existing generation profile of Japan's utility industry. Given the regulated nature of the industry, it is fairly simple to find publicly available information on the 11 firms that currently control ~80 percent of the power generation in Japan as well as regulatory information concerning Feed-in-tariff programs and other government renewables subsidies. The remaining ~20 percent of the generation mix is provided by independent power producers (IPPs) and heavy industrial companies that produce their own electricity (BMI, 2016c).

From here, this research will calculate the total cost for the determined range of scenarios in a method very similar to those used by the Nuclear Energy Association (NEA) and the International Energy Association (IEA) that outlines the process for determining the LCOE. LCOE represents the cost of providing electricity. This process is also supported by the Energy Information Administration (EIA) as outlined in a report released in 2013 named the *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants*. Total electric plant costs are represented as the sum of capital costs, fixed costs, and variable costs which are in turn dependent on factors such as plant capacity (MW), capacity factors (percent), and heat rates (Btu/MWh), a relative measure of efficiency and used in the calculation of fuel consumption (EIA, 2015b). The 2015 report by the IEA and the NEA titled *Projected Costs of Generating Electricity* provides regionally specific information on the LCOE for different technologies. These processes involve determining fixed costs that include carrying costs and fixed operations and maintenance (O&M) expenses. Then, this analysis will turn to variable costs, the two most important of which are fuel and emission costs, as they will be the major differentiable determinants of total cost between thermal asset classes (IEA, 2016).

Finally, this analysis will culminate in the development of a total cost curve for various asset mix scenarios which uses randomized variables such as fuel costs, emission costs, and the mix of renewable and thermal generation capacity to determine a potential decision set for optimal generation development. After this analysis, the paper will return to the hypothesis and see whether the current and future environment will indeed support the feasibility of low-carbon emission at a reasonable total cost to the consumer. With this curve in hand, it will be apparent at what level these variables will make the development of low-carbon sources more attractive than conventional fossil fuel-based generation.

ANALYSIS AND COLLECTION OF RAW DATA

As stated above, this process began with acquiring data on projected energy consumption by Japan in the year 2025 from BMI. However, there was only projected information provided until 2024 so an average growth rate over the projection years of ~1 percent was applied to the final year, yielding a final energy consumption of 1014TWh in 2025 (BMI, 2016c). The previous 9 years worth of data was projected using information provided by the Statistics Bureau of Japan and the EIA.

With this information in hand, the process began of collecting information from each of the 11 regulated utilities to find a breakdown of their assets in each of the different areas among thermal, renewables and nuclear generation. However, because only ~80 percent of generation is produced by these utilities, it was necessary to impute the remaining generation capacity by taking available total generation figures from BMI for each asset class and then recursively determining the remaining thermal and renewable generation that is attributable to independent power producers and heavy industrial companies. Nuclear generation has additional regulation and therefore detailed information on these reactors is more readily accessible. Furthermore, specific information regarding the breakdown of Japan’s renewable energy was also provided by BMI and used to reconcile with publicly available information due to the large number of privately held JV IPPs. This was performed by taking the MWh discrepancy and dividing it by the number of MWh that a single MW that each generating asset can produce at standard regional capacity factors provided for Japan by the EIA, as seen in **Exhibit4**.

In summation, Japanese nuclear runs at 50 percent capacity, hydropower runs 19 percent, solar runs at 20 percent, wind runs at 22 percent, coal runs at 62 percent, gas runs at 44 percent and oil runs at 26 percent (EIA, 2015a). The thermal generation numbers were taken from BMI. The breakdown of generation can be demonstrated in **Exhibit 5** in terms of unadjusted MW, reconciling the utility, IPP and heavy industry generation capacity. In total, these calculations fell within 2.5 percent of industry aggregate data. It is important to have an accurate breakdown of these values so that they can be manipulated in the following simulation to represent different asset mix cases.

The next step, since a large component of this analysis relies on the accurate reporting of CO_2 emissions by different generating assets, requires finding an accurate way to calculate total emissions. There are a number of different reporting methods between the OECD, EIA and the WNA that all report CO_2 emissions either by tons or lbs per kWh of generation, based on differing heat rates, an inverse measure of efficiency, for aggregate generating technologies. These calculated values were then compared with the UNFCCC 2015 estimate reference and the closest value was chosen as the method for calculating emissions. However, the UN provided no regional methodology as to how they reached this calculation. As a result, the closest was the OECD methodology, producing emissions totals within ~1.3 percent (IEA, 2014). A full breakdown of the emissions by asset type per unit of generation can be seen in **Exhibit 6**.

Finally, the last component of data collection before the case simulation was the LCOE values that were in part provided by the methodology in the IEA and NEA 2015 report, *Projected Costs of Generating Electricity*, which provides the cost of providing electricity from different generating asset sources. However, since the vast majority of countries outlined in the report, including the United States, completely decommissioned their use of oil-fired generation beyond minimal peaking plants, the values for oil generation were not included in the most recent edition. As such, a 2005 IEA and NEA report was used to approximate the total cost for oil, inflating the values in the report forward by the average inflation over this period (IEA, 2006). These calculated values were comparable to the oil LCOE numbers provided by the EIA in 2015 for dormant crude and fuel oil peaking plants in the United States. The equation for LCOE is given in **Exhibit 7**.

In essence, this formula takes all of the payments for capital costs (replacement costs), fixed and variable O&M, carbon emission costs and decommissioning and salvage costs for a single technology, discounts those costs and then spreads the cost across the potential amount of generation that asset can produce over the assumed life of the asset. While these costs were provided in full by the report, there are some striking differences between these numbers and some international average costs provided by the Institute for Energy Research (IER) (IER, 2014). The average costs at different discount rates as well as the average values calculated and used in this paper are provided in **Exhibit 8** as well as comparisons to the IER values in the subsequent graph (IER, 2014).

The primary differences are among the calculated versus reported cost of conventional combined cycle turbine generation (natural gas) and all the different forms of renewable energy. The differences in natural gas may be attributable in part to an increased demand in the wake of Fukushima Daiichi relative to the amount of available technology and limited resources in Japan, especially with the difficulty and costliness of importing liquefied natural gas (LNG). Geothermal and biomass can be referred to as exceptionally limited sources due to the scarcity of land available for geothermal beyond the scope of natural preservation (hot springs) or wood resources used in biomass (Hienuki et al., 2013). Finally, wind has faced substantial regulatory approval for the reasons stated above, solar PV has increased due to heavy demand and hydroelectric power is nearly at fully realized capacity which means that the only resources available are micro-hydroelectric sources which are more costly on a per MWh basis than large-scale hydroelectric projects (Vivoda 2014, 149). As such, with seemingly reasonable explanations for the discrepancies between the calculations using the methodology in the IEA and NEA report, these values will be used in the calculation of total cost later in this paper.

MONTE CARLO SIMULATION

In order to provide a randomized range of various asset breakdown, fuel price, and emission cost scenarios, this paper uses a modified version of the Monte Carlo simulation, the construction of which will be outlined in the following pages.

Firstly, in order to adequately project the possible changes in fuel prices, historical month over month changes for Japanese coal, LNG and crude oil prices were pulled from Bloomberg and another website, Quandl, which provides regional commodity index information. The remaining fuel, Uranium Hexaflouride (UF6), has limited recent information provided and is largely exchanged in dark markets due to concerns with security. However, contracts for large quantities of UF6 are purchased on futures contracts over the course of decades meaning that the amount of UF6 that Japan needs to fuel their nuclear generators is completely contracted through the projection period. As such, in the calculation of the LCOE for nuclear assets, these costs are considered fixed and thus do not fluctuate with market prices. See **Exhibit 9** for a graph of all commodity prices used in this simulation.

With this historical information, a co-movement beta was calculated for each of the different sources given the standard deviation of historical percentage movements. The base (market) commodity was arbitrarily chosen as coal to calculate these betas. These co-movement betas were calculated by the taking the covariance of the percentage movements for each pair of commodity in relation to coal and then dividing by the variance of the coal percentage movements. In order to determine the movement of fuel prices, a random number between 1 and -1 was chosen and applied to the standard deviation as a percent of total price of the first commodity, coal, and then all subsequent moves were determined using the co-movement betas. These betas can be seen in **Exhibit 10**.

With all of the relevant raw information collected, the simulation needed a set of parameters regarding the range that relevant variables, namely, the future asset mix (MW), carbon emission costs, and carbon remission credits, could fluctuate within. Again, the calculation of these boundaries was largely recursive and was focused on closely matching the Paris Accords INDC projections for relative electricity generation by asset class. The closeness of these calculated values to the INDC proposed values can be seen in **Exhibit 11**. On average, the generation percentages for each group fall within 1 percent of the projected totals with the exception of oil which falls within 2 percent.

The boundaries of each asset class were determined as a percentage of the current installed base that, as noted above, was determined by using public information from the 11 primary utilities as well as reconciliatory calculations determined by using research provided by companies like BMI. Something important to note regards the inclusion of nuclear in the future asset mix. As has been remarked by a number of scholars, nuclear tolerance follows rather cyclically in Japan wherein despite current protestations, tolerance will always return to predisaster levels, as is evidenced from previous nuclear controversy (Dominguez et. al., 2014). As such, the bounds are rather tightly contained with a lower limit of maintaining 90 percent of installed capacity up to approximately 150 percent of currently installed capacity, which would approximately reflect the possibility of continuing incomplete projects discontinued in the wake of Fukushima Daiichi. A full breakdown of the asset boundaries can be seen in **Exhibit 12**. These simulation boundaries are supported by qualitative observations from BMI (BMI, 2016a/b).

Other important considerations include that there is no possibility of decreasing the installed base of coal-fired generation, a maximum 30 percent decrease in the amount of natural gas and at minimum of ~70 percent decrease in oil-fired generation (UNFCCC, 2015). There is extremely limited upside for geothermal and biomass on an already limited installed base and consensus estimates agree that hydroelectric resources of any consequence are at capacity. Solar energy is modeled as having significant upside of up to 300 percent installation as well as wind at 400 percent, according to a wide range of estimates provided by BMI and Bloomberg New Energy Finance (BNEF), among others (Vivoda 2014, 145).

With these boundaries in place, the simulation then randomized the asset mix of each of the relevant asset classes: coal, natural gas, oil, hydroelectric, solar, wind, geothermal, and biomass. From each of these scenarios, of which there were chosen to be 1000, the amount of possible generation for each case was determined by multiplying the installed MW base under that scenario, by the number of hours in a year 8766, a year of 365.25 days to normalize under long-run scenarios the presence of a leap year, and then multiplying this by the assumed average capacity factors outlined above. The total amount of generation was then calculated and compared to the previously determined projection of energy consumption in year 2025. From these generation amounts and the LCOE per MWh calculations, as outlined above, were used to calculate the total cost of the system. Similarly, the amount of total CO_2 emissions was calculated for each of these sources using the OECD values mentioned above.

Since the amount of electricity generated will always equal the amount demanded in any properly functioning energy system, a cost waterfall was created in order to reconcile scenarios in which there was either too much or too little generation. The assumptions include that generation from any renewable energy was taken as fixed and that the only generation increase or decrease came from coal, gas or nuclear assets, ignoring any potential upside in oil generation as inert due to policy overtures stating the intent to rigidly decrease oil generation. The logic in restricting renewables as fixed is that they only produce when the relevant resource (wind, sun, etc.) is active. These values are relatively fixed in the long-run based on meteorological observations. This waterfall took the lowest cost generation among these three sources up to an assumed maximum capacity factor of 90 percent. This assumes that no plant can run at 100 percent capacity due to scheduled maintenance and repairs. Once the lowest cost source was depleted, the next lowest cost source was used and so on until the demand was filled. Conversely, if there was an excess in generation, the highest cost source, including oil generation, was decreased to its minimum assumed capacity factor, followed by the next highest cost source and so on until there was no excess generation. The corresponding increase and decrease in costs was added to the specific simulation case so that total cost values were complete. Similarly, the corresponding increase or decrease in emissions was added as a result of these changes in generation for each case.

With all of these incremental changes for each scenario under the simulation, there are a range of total LCOEs for each generating technologies that can be seen in **Exhibit 13**. Having all of the adjusted information regarding total system cost and emissions for each, it was then important to compare the total cost of each case to the current total cost of the system as well as the emissions totals to those reduced amounts set forth by the Paris Accords INDC.

However, it is important to note that, as with all models, there are certainly augmentations that could be made to increase the accuracy of the results and thus improve the analytical conclusions drawn. Some input limitations might stem from the fact that only one source was used for the calculation of the LCOE. Furthermore, the recursive method that was used to calculated the excess thermal generation capacity that is attributable to IPPs and heavy industrial companies might be made more accurate given additional time to find plant-by-plant information from these companies or government agency. Within the simulation itself, the primary assumption that the underlying commodity prices for the different generating sources are not independent might be construed as inaccurate by some. Additionally, this model does not include the speculative incorporation of any factor that decreases the cost of new (renewable) technology over time. Furthermore, carbon emission cost price changes are assumed to be uniform. Finally, there were randomly ascribed ranges for changes in FITs and CO_2 charges due to a lack of information as to policy initiatives. However, given the wideness of these ranges (0 percent - 300 percent), it is reasonable to assume that the vast majority of future scenarios are included.

SIMULATION RESULTS DISCUSSION

The simplest outcome of this simulation can be seen in a graph that charts all of the possible total costs from the lowest to the highest value, broken up between the different classes of generating assets. The range of total costs for the entire 1000 cases of the simulation can be seen in **Exhibit 14**.

The two lines on the graph represent the two common thresholds that were used for relative comparison purposes, cost parity with the current system (0 percent) and the upward limit of consumer cost increase tolerance (8 percent), \$160.736bn and \$173.595bn, respectively. This translates into 27 percent of cases achieving cost parity with the current system and 56 percent achieving total cost within the increased 8 percent tolerance threshold for low-carbon. For the entire simulation, approximately 64 percent realized the Paris Accords stipulations in terms of total emission reductions and, due to the waterfall methodology mentioned above, 100 percent of cases achieved the exact amount of electricity demanded by the system. By way of summary statistics, the minimum, median and maximum costs can be found in **Exhibit 15,** with a minimum cost of 21% and a maximum cost increase of 39%.

However, since only one component of this analysis is cost, it is important to consider what number of cases fall within the various cost tolerance ranges as well as achieving the level of decreased emissions required. When this new constraint is added, the number of cases for 0 percent, 4 percent and 8 percent cost falls is 16 percent, 26 percent and 35 percent, respectively. Looking among these cases, there are a number of different observations regarding the breakdown of generation and cost for these cases among renewables, thermal and nuclear. These results can be seen in **Exhibit 16**.

Despite there being a limited number of scenarios that satisfy both conditions, the asset mix breakdown of those cases provides some interesting insights. A table with the complete summary statistics can be found in **Exhibit 17**. So, looking at the case with the highest cost, it is evident that renewables by cost are approximately 33 percent, while coal and gas are 23.7 percent and 27.4 percent, respectively. In the median case, the percentage of renewables by cost drops to 26.1 percent and coal and gas increase to 29.5 percent and 33.4 percent, respectively. In the minimum case, the renewable percentage by cost drops to its lowest of 23.8 percent, coal increases to 32.3 percent and gas drops to 26.2 percent. What is most interest about the breakdown of these cases is the change in the total cost percentages across the different cases. What these numbers indicate follows conventional wisdom in that the higher the percentage of coal relative to other generating groups, the lower the cost of the system. However, the fact that the total gas by cost increases and decreases across this range indicates again the fact that, when managed aggressively to supplant coal, can produce decreases in cost as well as reduced emissions. In further support of this proposition, there is considerable information to be gleaned from the cost waterfall which determines how systems manage over or under production of electricity. As seen in **Exhibit 18**, there are considerable emissions savings to prioritizing the implementation of gas-fired generation above coal. Replacing a single MWh of coal with gas can decrease emissions by ~57 percent. However, there is a $25/MWh premium on gas-fired generation relative to coal. Breaking down the cost differences further, of the ~$122/MWh for coal, $25 is ascribed to carbon costs, for the ~$148/MWh for gas, only $11 is ascribed to carbon costs. Therefore, with a uniform 78.6 percent increase in carbon emission costs, gas-fired generation is preferred.

As is evidenced by the exhibits regarding total generation and cost, there is a cost and supply mismatch between renewable and thermal energy wherein the cost of renewables is significantly higher (~10 percent) than the average generation amounts and vice versa for thermal and nuclear generation, indicating that fossil fuel generating technologies, even among potentially adverse carbon costs scenarios, are much more cost effective than renewable energy technologies. For example, among the cases that were able to achieve cost and emissions requirements, the average emissions cost increase incorporated into this analysis ranges between

50.3 percent and 54.8 percent. However, despite these averages, there are individual cases in which the CO_2 cost movement in cases below the 8 percent cost threshold span the entire range from 0 percent - 300 percent of the current carbon tariff levels.

Additionally, the average fuel cost change for this simulation incorporates a decrease in fuel prices, as seen in **Exhibit 19**. One consideration that many scholars have considered is the impact of price changes on overall cost viability. However, employing the same methodology as was used to calculate what percentage increase in carbon emission costs was required to make natural gas more favorable, it seems improbable that price can impact this cost viability. As seen in **Exhibit 20**, since the fuel cost per MWh of natural gas is dramatically larger as a percent of total LCOE, at 70.5 percent versus 29.2 percent, natural gas and coal prices would both have to decrease at least 63.3 percent to achieve cost parity between the two technologies. Adding in the previous assumption that cost movements are not independent, a 63.3 percent in liquefied natural gas would necessitate an impossible 558.0 percent decrease in the price of coal. However, changing the assumption that commodity prices are not independent would certainly change the viability of this required cost decrease scenario.

In an attempt to find any relationships that might appear to be correlative, it was important to analyze the result of plotting multiple pairings of variables against each other. The primary variables chosen for analysis were as follows: relative cost to current (percent), IDNC (emissions) standards, and the percentage of total generation provided by renewables. The graphs of these relevant relationships can be seen in **Exhibit 21**.

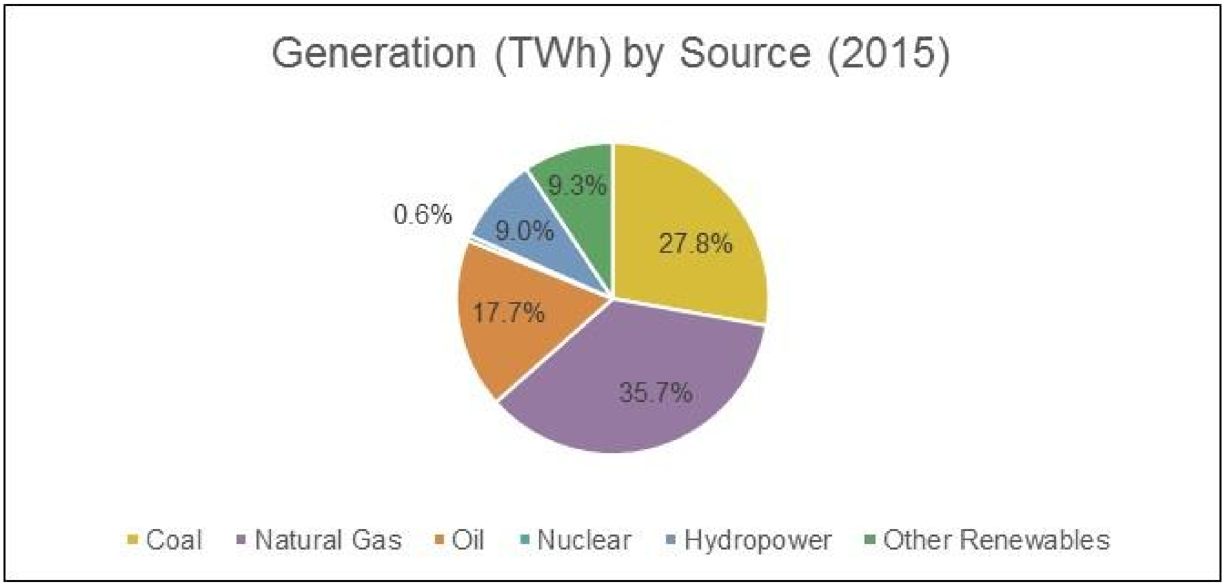
While none of these graphs individually can key to any specific relationship, taken together they begin to form an interesting potential interpretation. As noted above, there is some notion to the idea that reducing emissions might be a function of managing carbon costs while incorporating renewables in order to maintain total generation levels. In the first graph of the exhibit, there is a positive relationship between the total cost of the system and the positivity of relative emissions to the Paris Accords. At first, this might be seen as counterintuitive as it might follow logically that scenarios with higher levels of renewables, and thus lower emissions, would be the costlier ones. On the other hand, this may well be due to the fact that increased emissions costs of approximately 50 percent lead to a relatively high cost for coal-fired generation which would spur the usage of natural gas under the waterfall method above. Similarly, in the second graph, the uniform distribution of renewable generation percentage relative to emission costs may logically lead to the interpretation that the development of renewables might be of secondary importance when considering the impact of incentivizing certain thermal generation assets over others, like gas versus coal, through the use of carbon emission charges.

CONCLUSIONS

In conclusion, there is a low probability that, under these randomized scenarios, Japan is able to achieve their emissions reductions while maintaining reasonable costs. At the upward cost tolerance of 8 percent, this probability is approximately 34 percent given other variables. Furthermore, this reduction is also contingent on a rather significant increase in the cost of carbon emissions, imposed by the government. With approximately 78 percent relative increase in carbon costs, under a number of scenarios, gas generation will be become more economically efficient relative to coal, which would dramatically decrease carbon emissions through the waterfall method used to adjust for over and underproduction potential. As such, returning to the initial hypothesis that stated it is probable that Japan will be able to achieve low carbon emissions while maintaining costs, the results of this study, on average, contradict this assertion.

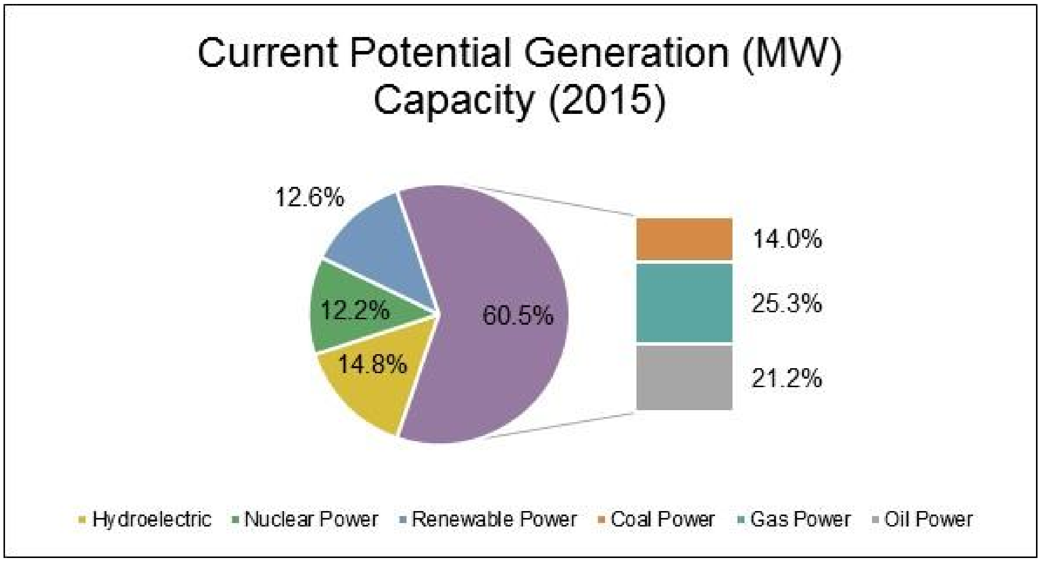
Further research may consider the implementation of a number of different systems that might increase this probability, such as the development of a green bond market, carbon emission trading schemes or recent developments in the retail securitization of renewable energy projects that are projected to decrease the retail cost of implementing renewables.

Exhibit 1: Japanese Generation (TWh) by Source in 2015



Source: BMI, 2016c

Exhibit 2: Japanese Potential Generation Capacity (percent) by Source in 2015



Source: BMI, 2016c

Exhibit 3: Paris Accords INDC Proposed Generation Breakdown

Paris Agreement Generation Breakdown	
Type	
Coal	26%
Natural Gas	27%
Oil	3%
Nuclear	21%
Renewables	23%
Total	100%

Source: UNFCCC, 2015

Exhibit 4: Japanese Capacity Factors in 2015 (EIA)

Capacity Factor by Source and Region		
Source	**Region**	**Capacity Factor**
Coal Generation	Japan	62.0%
Gas Generation	Japan	44.0%
Oil Generation	Japan	26.0%
Nuclear Generation	Japan	50.0%
Hydroelectric Generation	Japan	19.0%
Solar Generation	Japan	20.0%
Wind Generation	Japan	22.0%
Biomass	Japan	51.0%
Geothermal	Japan	64.0%

Source: EIA, 2015a

Exhibit 5: Recursive Generation Allocation among Non-Reported Industrials and NPPs

Generation Source	Total (MW) Utilities	Total (MW) Others	Total (MW)	PoT	Difference
Hydroelectric Power	50720	-	50720	14.8%	0.0%
Thermal Power	141550	-	207217	60.5%	3.2%
Coal	36307	11579	47886	14.0%	n/a
Gas	66893	19833	86726	25.3%	n/a
Oil	38350	34255	72605	21.2%	n/a
Nuclear Power	41647	-	41647	12.2%	2.8%
Renewable Power	43105	-	43105	12.6%	0.0%
Total	**277021**	**-**	**342688**	**100.0%**	**2.3%**

Exhibit 6: Emissions Calculation Table by Input Source

Total Emissions (Fossil Fuels)	Metric Tons (bn)	Difference
OECD	0.48	-1.3%
EIA	0.56	15.5%
WNA	0.54	11.5%
Aggregate	0.53	8.6%
UN Reference	0.49	-

Emissions Factors	OECD	
Fuel Type	**gCO2/kWh**	**tCO2/kWh**
Sub-bituminous Coal	920	0.00092
Other bituminous Coal	860	0.00086
Lignite	990	0.00099
Natural Gas	400	0.00040
Crude Oil	630	0.00063
Natural Gas Liquids	480	0.00048
Liquefied Petroleum Gasses	500	0.00050
Kerosene	650	0.00065
Gas/Diesel Oil	690	0.00069
Fuel Oil	670	0.00067

Source: IEA, 2014

Exhibit 7: Formula for Calculating LCOE (IEA & NEA Report)

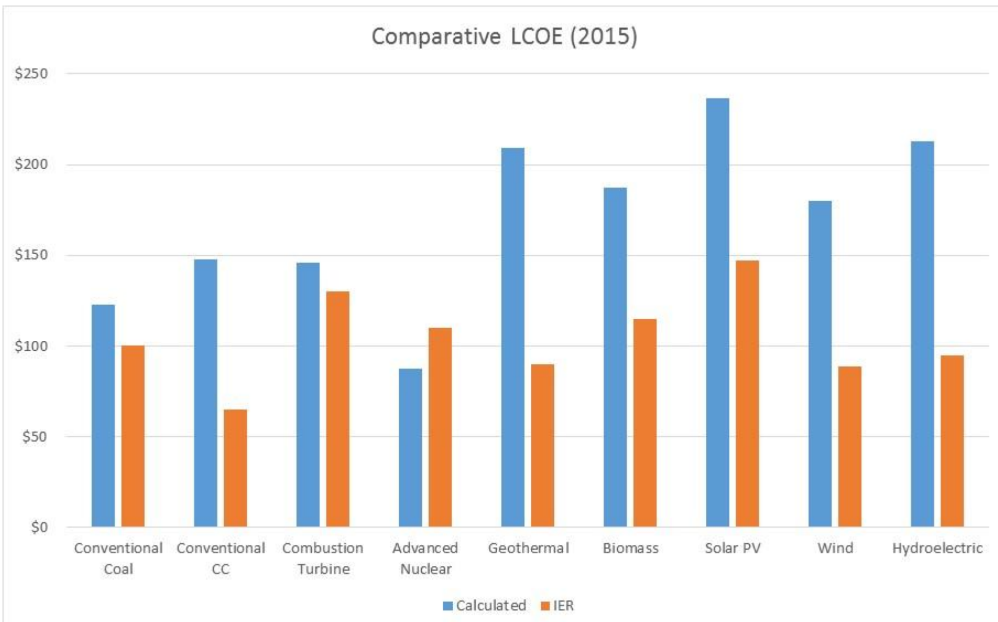
$$LCOE = \frac{\sum_{t=1}^{t}(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t)}{\sum_{t=1}^{t} MWh_t * (1+r)^t}$$

- Capital – Overnight capital costs (replacement costs)
- O&M – Operations & Maintenance costs
- Fuel – The cost of fuel inputs to generate MWhs
- Carbon – The cost levied against carbon emissions
- D – Decommissioning and salvage expenses, the cost to shut down a plant or its values at sale depending on the asset class
- MWh – megawatt hour, the amount of electricity 1MW of capacity produces over an hour
- r – the ascribed discount rate

Source: IEA, 2016

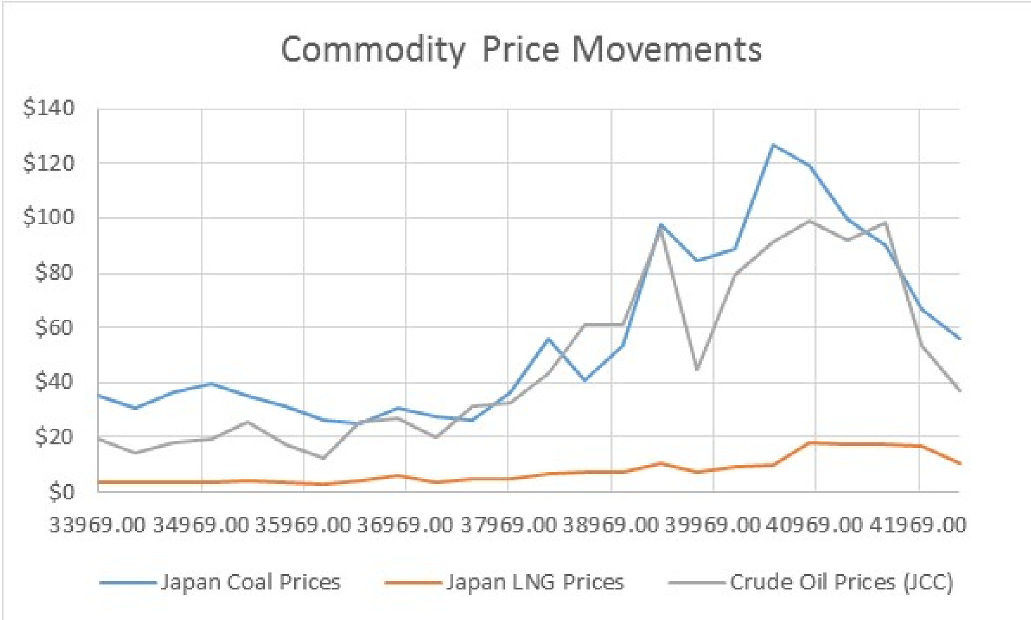
Exhibit 8: LCOE by Source and comparison to reported IER values

Condensed Total Cost Output				
	3%	7%	10%	Average
Coal	$121.6	$122.9	$124.0	$122.8
Gas	$147.4	$147.7	$148.1	$147.7
Oil	$139.1	$143.6	$155.0	$145.9
Nuclear	$85.1	$87.6	$90.1	$87.6
Hydroelectric	$102.7	$214.2	$321.4	$212.8
Renewables	-	-	-	
Solar	$199.3	$270.5	$332.0	$267.3
Wind	$134.6	$182.1	$223.4	$180.0
Biomass	$162.7	$188.0	$210.9	$187.2
Geothermal	$142.3	$209.9	$275.9	$209.3



Source: IEA, 2016

Exhibit 9: Commodity Prices (Coal, Gas, Crude)



Source: Bloomberg L.P., 2015, Quandl, 2015

Exhibit 10: Commodity Price Co-Movement Betas

Commodity Price Co-Movements (Yearly)				
		Coal-LNG	Coal-Uranium	Coal-Crude
		38.55%	70.69%	52.36%

Exhibit 11: Calculated Generation Amounts by Source Relative to the Paris Accords INDC

Percentage Generation Breakdown				
Type	**Current**	**Calculated**	**Proposed**	**Difference**
Coal	28.3%	26.0%	26%	**-0.1%**
Natural Gas	36.4%	27.1%	27%	**-0.5%**
Oil	18.0%	2.9%	3%	**1.8%**
Nuclear	0.6%	20.9%	21%	**0.3%**
Renewables	16.8%	22.9%	23%	**0.3%**
Total	100.0%	100.0%	100.0%	**0.0%**

Source: UNFCCC, 2015

Exhibit 12: Simulation Potential Asset Mix Ranges by Source

Projected Generation Inputs			
Technology	**Capacity (MW)**	**Range (Bottom)**	**Range (Top)**
Coal	47886	100%	110%
Gas	86726	70%	100%
Oil	72605	0%	37%
Nuclear	41647	90%	150%
Hydroelectric	50720	100%	100%
Renewables	43105	-	-
Solar	35800	100%	300%
Wind	2822	100%	400%
Biomass	3963	100%	125%
Geothermal	520	100%	125%

Exhibit 13: Simulation LCOE Ranges among Asset Classes

Cost Ranges	Coal Generation	Gas Generation	Oil Generation	Nuclear Generation	Hydroelectric Generation
Min	$107.0	$141.8	$135.5	$77.3	$205.8
Median	$160.3	$163.9	$183.4	$87.4	$209.3
Max	$215.4	$187.2	$232.8	$97.9	$212.8
	Solar Generation	**Wind Generation**	**Biomass Generation**	**Geothermal Generation**	
Min	$260.3	$173.1	$180.2	$202.4	
Median	$263.8	$176.5	$183.7	$205.9	
Max	$267.3	$180.0	$187.2	$209.3	

Exhibit 14: Graph of Total Cost for each Case in the Simulation Run

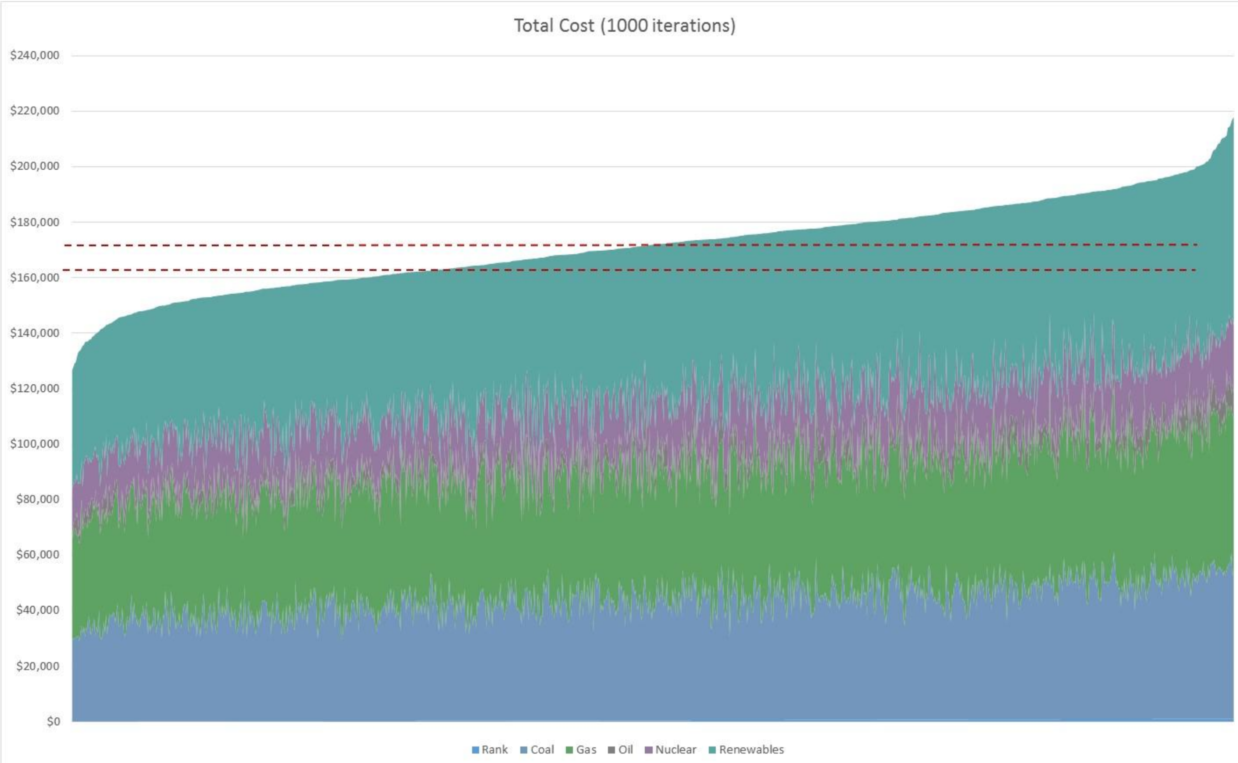


Exhibit 15: Simulation Cost Summary Statistics

Cost Breakdown	
Minimum	-21.2%
Median	6.6%
Maximum	38.9%

Exhibit 16: Breakdown of Simulation Runs by Asset Generation and Cost

Renewable Generation (8%)	
	Percentage
Hydroelectric	8.6%
Solar	12.3%
Wind	1.4%
Biomass	2.0%
Geothermal	0.3%

Thermal & Nuclear Generation (8%)	
	Percentage
Coal	27.6%
Gas	28.7%
Oil	3.0%
Nuclear	22.3%

Renewable Generation Costs (8%)	
Coal	25.4%
Gas	27.5%
Oil	2.8%
Nuclear	11.7%
Renewables	32.7%

Exhibit 17: Breakdown of the Cases that Satisfy both Conditions

Cost and Emissions Summary	
Cost Threshold	**Percentage**
0%	16%
4%	26%
8%	35%

	Coal	Gas	Oil	Nuclear	Renewables	%CO2 Emissions
Maximum Case	23.7%	27.4%	4.0%	11.5%	33.4%	32.6%
Median Case	29.5%	33.4%	0.2%	10.8%	26.1%	41.3%
Minimum Case	32.3%	26.2%	5.5%	12.2%	23.8%	90.4%

Exhibit 18: The Benefit of Gas versus Coal Generation in the Waterfall Method

	Coal Allotment	Gas Allotment
Generation Allotted	17191274541	15047322915
Emissions	13893695	6018929
Reduction	**43.3%**	**7874766**
Cost Increases ($/MWh)	-	$25

Exhibit 19: Simulation Fuel Price Summary Statistics (Coal, Gas, Crude Oil)

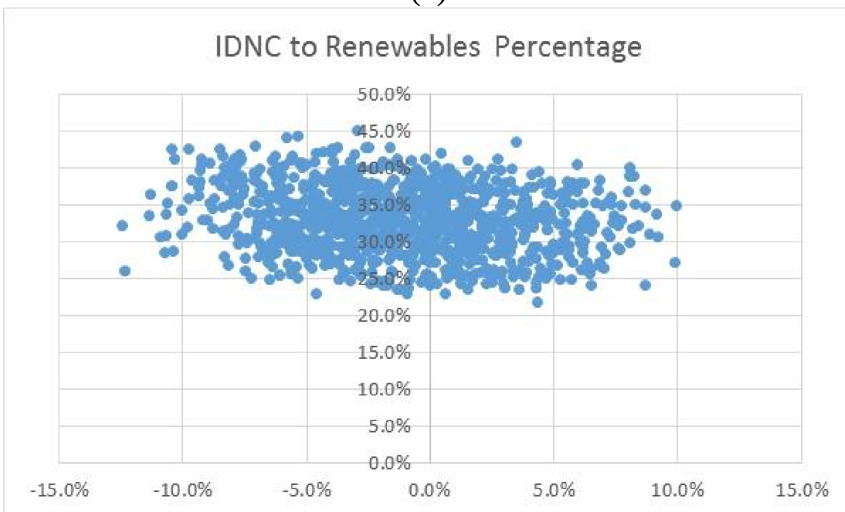
Fuel Price Breakdown	
Coal	**-9.4%**
Gas	**-3.6%**
Oil	**-4.9%**

Exhibit 20: Fuel Price Change Requirements for Gas and Coal Price Comparability

Fuel Price Change Requirements		
	$/MWh	**PoT**
Coal Fuel Costs	$35.9	29.2%
Gas Fuel Costs	$104.1	70.5%
Cost Difference	$68.16	-
Cost Change LNG	-	-63.3%
Cost Change Coal	-	-558.0%

Exhibit 21: Two Variables Comparison (Paris Accords emissions relative to renewable percentage by generation and cost relative to the present to emissions standards relative to Paris Accords)

(1)



(2)

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