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Comparative Analysis of Transitional Energy Sources for Power Generation (Nuclear, Hydro, Wind, Solar PV, Natural Gas and Underground Coal Gasification)

Author: Muhammad Fahim Khan *

Dissertation

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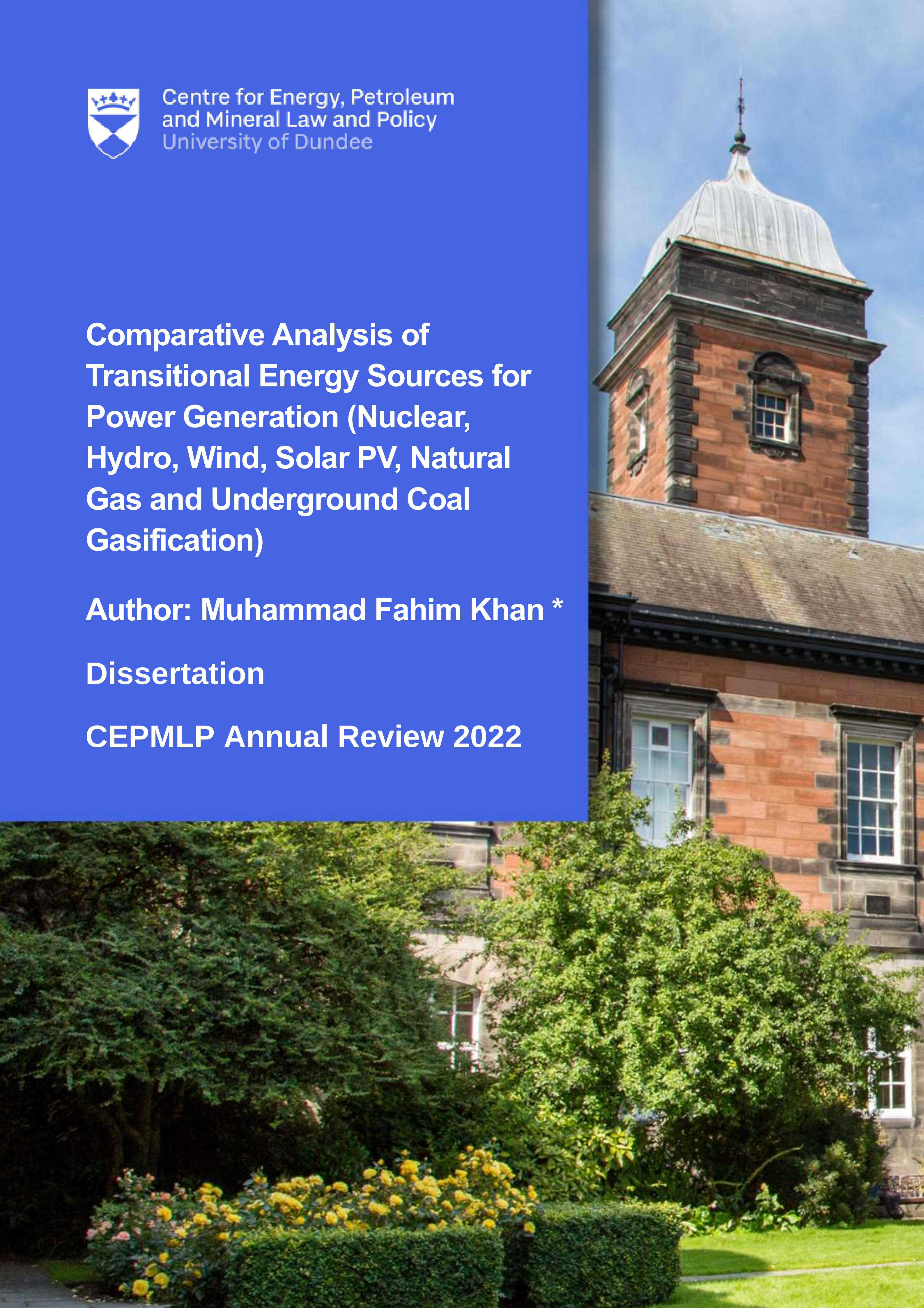

Abstract

Due to increasing concern over environmental damage that fossil fuel consumption is causing on a global scale, alternative methods of energy and power production are being widely researched and utilised, pursuant to fossil fuel replacement in the energy mix. This study focuses on transitional fuel types, technologies, other non-fuel forms of energy generation, and their implementation in the real world to determine whether they are economically, commercially and politically attractive options. This includes nuclear power, and renewable energy sources (RES) such as hydroelectricity, wind and solar photovoltaics (PV). The study also analyses the oldest natural gas in the context of its purported status as a (clean energy) "transition fuel" in power generation, and another technology, namely underground coal gasification (UCG), which has the potential for producing cheap and reliable energy, albeit through the combustion of coal, a fossil fuel, underground. These fuel sources are analysed initially on their techno-economic feasibility. Then both sectoral risks investor trends are critically examined in the context of relative affordability and economic attractiveness. A further analysis is conducted into public policy requirements/ implications of these different fuels sources. Nuclear power plants (NPP) are a controversial method of power production due to the risk for potential catastrophe as realized by the Fukushima and Chernobyl disasters. Hydro and wind power with the current technology and the lack of constant provision of both energy sources are unable to provide a stable and reliable rate of energy production. Solar PV offers huge upside potential, even as the technology has not reached that potential yet. Natural gas being dependable becomes far less competitive with Carbon capture and storage integration. UCG has certain advantages as a transitional fuel over other fossil fuels and renewables by being able to provide constant power and clean energy due to the fact that best practices in UCG projects involve carbon sequestration and contaminant neutralization.

* M. Fahim Khan is an experienced Pakistani legal practitioner with specialization in regulatory matters for high investment projects. He holds a Bachelors in Law from the University of London (UK) and a Master of Laws from the Centre of Energy, Petroleum and Mineral Law and Policy, University of Dundee (UK) with Distinction.

Abbreviations

ABWR:	Advance Boiling Water Reactor
BNEF:	Bloomberg New Energy Finance
BOS:	Balance of System
CBM:	Carbon Budget Model
CCGT:	Combined Cycle Gas Turbine
CCS:	Carbon Capture and Storage
CO2:	Carbon Dioxide
CSP:	Concentrated Solar Power
DEHP:	Department of Environment and Heritage Protection
DGSNR:	Direction Generaly De La Surete Nucleaire Et De La Radio Protection
DOE:	Department of Energy
ECA:	Export Credit Agency
EPC:	Engineering Procurement and Construction
FiT:	Feed in Tariff
GHG:	Green House Gases
GWh:	Giga Watt Hour
IEA:	International Energy Agency
IFC:	International Finance Corporation
IRENA:	International Renewable Energy Agency
ITC:	International Tax Compact
kW:	Kilo Watt
kWh:	Kilo Watt Hour
LCOE:	Levelized Cost of Electricity
MVP:	Mean Variants Portfolio
MW:	Mega Watt
MWh:	Mega Watt Hour
NEA:	Nuclear Energy Agency
NGCCT:	Natural Gas Combined Cycle Turbine
NPP:	Nuclear Power Plant
NREL:	National Renewable Energy Laboratory
O&M:	Operation & Maintenance
OECD:	Organisation for Economic Cooperation and Development
PPA:	Power Purchase Agreement

PV:	Photovoltaic
RES:	Renewable Energy Systems
SPV:	Special Purpose Vehicle
ST:	Social Transition
TWh:	Terra Watt Hour
UCG:	Underground Coal Gasification
UCGCC:	Underground Coal Gasification Combined Cycle
WEO:	World Energy Outlook

Contents

1.Introduction

In the current era the world is experiencing a period of drastic change in the energy markets. There is a growing need for energy. Many countries are energy insecure and those that have energy security are barely maintaining growth in production while needs are rising faster. There is a necessity to balance energy production with environmental protection as decades of associated projects have taken their toll on the planet's ecosystem. For this reason, there is a global energy transition taking place away from fossil fuels and towards, *inter alia,* RES. Current RES technologies have not allowed us yet to adequately harness renewable sources of energy sufficiently to fully replace fossil fuel consumption, or in a way that overcomes the challenges of intermittency of supply whilst retaining competitive levels of commerciality (Lyman, 2016). Until this milestone is achieved states and independent companies are looking for a viable energy source for power production which is environmentally friendly. The main contenders for this transitional period are nuclear power, RES (e.g. benefiting from advancements in technology) and natural gas.

Excepting for occasional usage in, for example, the former Soviet Union, UCG is a relatively new form of power generation that is being explored to ascertain its potential and viability (Beath and Davis, 2006). Deep coal resources are converted into synthetic gas capable of producing electricity, fuels and various chemicals (Yang and Ge, 2016). Every project before execution is evaluated on three core components for viability. The first is the economic commerciality of the project. This is done by evaluation of capital expenditure (capex), operational expenditure (opex), average production capability and difference between local market price and cost price per production. These are based on the physical nature of fuel, its location and the ability to accurately quantify how much power they can produce. An essential cost metric, and one that is invaluable in comparing costs between different forms of primary energy generation and technology use, for any power plant is that of energy cost per unit generated, that is the levelised cost of energy (LCOE). LCOE represents the absolute expense to construct and work a power plant over its lifetime partitioned by the complete power yield dispatched from the plant over that period, subsequently regularly unit used is cost per megawatt hour. It considers the financing expenses of the capital portion (not simply the 'overnight' cost) (U.S. Department of Energy, Office Indian Energy Policy and Programs, 2015).

The second limb is the financing policies of various institutions in order to secure capital for power production projects based on the energy source. Projects with higher risk factors are unlikely to be funded by private entities except at commensurately higher risk premiums, and may require government sponsorships, subsidies and support to be economically viable. Another consideration is State public policy towards a type of fuel or method of energy production which may make it unwilling to invest. If, however risks are minimized and the project seems profitable entities such as bank syndicates maybe willing to fund these.

The final consideration is the policy framework surrounding the particular method of production. Due to the vitality of such projects to a state's economy combined with the historically negative impact they have had on ecosystems, energy projects tend to be heavily regulated. These regulations depend on government policies and attitude towards a type of fuel. A change in government can lead to a change in policy creating political risk for long term projects making them less profitable or in some cases complete sunk costs. Policy factors will be analysed in lieu of a states need to ensure public interest (Greenhouse gas emissions, groundwater contamination, ecological disasters etc.) and energy security (cheapest method of producing constant power) (N.V., 2017).

2.Research Question

This research aims to determine how the subject energy source power production projects would tend to fare in comparison with each other and to determine what is the best option in short and long term for energy production. This will be in relation to the three limbs mentioned above by analysing the relevant quantitative and qualitative data.

3.Importance of the Question

The hunt for alternative fuel sources which are economical and environmentally friendly is a global issue. The Paris Agreement is an international treaty entered into for the sole purpose of tackling climate change by party states by using economic and social transformations over various sectors to reduce GHG emissions (UNFCC, 2022). Conventional fossil fuels have been in decline for years as after the Paris Agreement the global perception has begun to favour renewable energy. The current market structure especially after the COVID 19 pandemic has irreversibly changed the dependence on oil in the energy market and its necessity. International oil companies (IOCs) such as Shell are also abandoning conventional oil projects in favour of alternative energy investments (Malek, 2018). Renewable energy with the current technology requires high amounts of investment to significantly contribute to a (any sizeable) country's energy mix.

Countries that lack the investment and/or the natural resources to produce a significant amount of energy from renewable fuels will look for other fuel sources that can economically provide a significant change in their energy mix while maintaining a similar lack of harm to the environment. Nuclear power is a rather controversial energy source for power production and requires high investments, however this is balanced out with production of cheap base load energy in the long run. Natural gas being the oldest and reliable transitional source for energy production is included so as to create a benchmark for comparison of other energy sources. UCG is a less common energy source for power production however it does carry certain potential. As UCG projects require a specific grade of coal which has limited use (for the purposes of energy production) or is economically unrecoverable, multiple countries such as China, India, Pakistan and Australia to name a few have access to a possible clean and cheap fuel source from a coal resource that previously may have been economically unviable to extract (mine), especially where the coal seams concerned extend offshore.

Modern UCG techniques also address issues such as groundwater contamination associated with shale gas extraction nor bear the risk of environmental catastrophe that are borne by nuclear power projects (British Geological Survey, 2020). While there is no assumption on part of the author that a single energy source is better in absolute terms than the others, it is essential to compare and contrast them in order to understand the advantages and disadvantages a specific project may have over the others. LCOE is taken as a critical (but not the only) factor for the comparison and accordingly this dissertation has a greater focus on this aspect of these projects. The author further hopes that by understanding these projects in the context of each other will encourage future lines of research to create efficient low carbon energy mixes in the power sector.

4.Literature Review

Comparative economics for using LCOE and other methods exist over a vast variety of literature. Regardless of certain objections to using LCOE as an apparatus for contrasting expenses across power production fuel types, for example, Synapse Energy Economics (2016), Schmalensee (2016), Hirth et al. (2015), among others. LCOE stays a basic apparatus, as it offers a few points of interest as cost measurement, for example, its capacity to standardize costs into a reliable configuration across decades and innovation types. Furthermore, it gives abundant adaptability to join numerous elements and boundaries to give extensive cost viewpoints. Thusly, it has become the most utilized tool for cost correlations among the numerous partners, for example, policymakers, analysts etc. (Rhodes et al., 2017).

There are numerous associations that gauge LCOE numbers on a yearly premise, a couple of them are BNEF (Frankfurt School-UNEP Centre/BNEF, 2018; 2017) that break down LCOE for the distinctive electricity generation technologies. IRENA gauges the renewable electricity production costs over the globe periodically (IRENA, 2018; 2015). Likewise, the IEA with its yearly lead report world energy outlook (WEO) (IEA, 2018; 2016) have estimations of LCOE up to 2050 for the distinctive innovations. Moreover, different government associations have created LCOE models tweaked for their particular nations, for example, US LCOE model by the Department of Energy (DOE) (USDOE and NREL, 2018) there is fluctuation in the approach to externalities and different parameters, as appeared in the comparative examination among these alongside a couple of other LCOE models in Foster et al. (2014). In spite of the fact that LCOE is a well-rounded and common procedure in assessing power segment financial matters, authors treat model definitions in different ways, in order to guarantee the model meets research goals and information accessibility (Foster et al., 2014).

There is much study done on risk assessment which is core for financing projects. Kitzing (2014) and Kitzing and Weber (2015) break down the investor interest generating quality of seaward wind parks with an income model and Monte Carlo simulation depending on wind availability and price of power. They find that feed-in taxes (FIT) prompt lower support costs than feed-in premiums (FIP) on the grounds that it creates a greater price risk for investors which leads them to demand higher returns in lieu of taking extra risk. Variable outputs from increasing RES share in the mix leads to greter power price volatility (Muñoz and Bunn, 2013, Redpoint, 2009 Green and Vasilakos, 2010, Pöyry, 2009, Green and Vasilakos, 2011, Pöyry, 2009). The significant inquiry, nonetheless, is whether more exorbitant cost unpredictability likewise converts into higher investment risk for the plants in the market. This simulation when done by Muñoz and Bunn (2013), fusing different risk factors (for example construction delay risk), shows significantly greater budgetary issues and risks for nuclear, Combined cycle gas Turbine and wind power if wind power replaces coal power.

The mean–variance portfolio hypothesis (MVP), at first created by Markowitz (1952) for financial protections, is utilized to advance plant portfolios by accounting for production hazards and their relationships to diminish portfolio hazard by diversifying. Awerbuch creates and directs MVP in different investigations from a social planner viewpoint (for example Awerbuch and Spencer 2007, Awerbuch and Berger, 2003, Awerbuch, 2000). The methodology is finessed in a few papers, for instance to catch RES accessibility too, as in Jansen et al. (2006) and Arnesano et al. (2012) and to consolidate it with investor and dispatch models, as in Sunderkötter and Weber (2012) and Delarue et al. (2011). A commonplace discovery of such investigations is that including advancements with high fixed costs, for example, RES, to the power blend including great portions of thermal plants with unpredictable fuel expenses brings down estimated portfolio risks (or expenses) for a number of risk factors, regardless of whether the capital concentrated technologies have greater expenses on an individual premise.

Fuel integration where advancement happens, for example, solar power, require government assurance and backing, until they can grow and accomplish cost equality or until policy internalizes externalities of contending innovations through instruments, for example, carbon taxation (Smith and Raven, 2012, Smith et al., 2005). In vigorously regulated sectors, for example, power production and conveyance, government strategical support is particularly significant. Consequently, the issue of STs for power have wide cultural and political components that define the timeline of STs. Progressively the writing on STs perceives the significance of such factors (e.g., Meadowcroft, 2009, Geels, 2011, Elzen et al., 2011, Grin, 2010, Flor and Rotmans, 2009, Meadowcroft, 2011). Of specific pertinence to this investigation is the function of stakeholders, explicitly the degree of collaboration or obstruction from the industry participants affected by the transition. Occasionally, STs are inserted in expansive social clashes over the future course of society, for example, happened in the contention among wind and nuclear power in Denmark (Jørgensen, 2012). In the United States and somewhat additionally in Australia and Canada, the expansive social clashes over sustainable power source are firmly associated with political questions between a conservative political groups that is connected to funding from the petroleum product sector and ecological protection that is connected to the labour groups (Hess, 2012). Nonetheless, even in European nations that are internationally perceived as pioneers of STs, for example, the Netherlands, there is developing acknowledgment that ST approaches have not been as fruitful as initially envisioned (van der Loo and Loorbach, 2012, Kern and Smith, 2008, Kern, 2012). As acknowledgment of the part of political and cultural contributions for STs have developed, pioneers of the field have ascertained more research is required (e.g., Raven et al., 2013, Coenen, 2011,).

Three significant factors are commonly distinguished in socio-technical changes (Geels, 2004). These consist of players and social gatherings; rules and organizations; and evolution of innovation and more extensive socio-specialized and monetary frameworks. Inside the classification of rules and organizations, Geels (2004) incorporates regularizing and psychological principles just as formal authoritative, administrative and policy systems. Different writers have treated fundamental thoughts, standards and assumptions regarding power frameworks, manageability and the function of the administrative bodies and market factors in power policy transition and plans as a different class of variable (Winfield and Dolter, 2014, Dryzek, 2013 and Doern and Toner, 1985).

This study aims to go beyond the current literature by first aggregating the data in order for drawing an easier comparative analysis. Secondly this paper focuses on economic, financing and policy factors not in an individual method but the interlink in them and how they play into one another. An example is how technical factors affect the economics of a project which then interplays with associated risks and attractiveness of the type project to the investor. This then further integrates into national policy of the fuel type, whether it provides enough advantages (energy security) for the government or do the disadvantages (public harm) offset the advantages or vice versa. The government will then accordingly either regulate or encourage the usage of that fuel source creating a feedback loop that either improves or worsens the economics of the projects and so on until change in policy. Furthermore, the importance of diversification of energy fuel usages is recognized in this paper and comparisons are not drawn to determine absolute superiority. They are drawn to distinguish the usages of the type of fuel (e.g. hydro for peak power or nuclear for baseload power) and provide information that leads to more efficient energy mixes.

5.Methodology

In order to determine comparative viability analysis will be carried out of documented projects for each fuel source. There will be an evaluation of the economic viability driven from physical characteristics, technical feasibility, attitudes of financiers towards the fuel source and policy barriers or encouragement and their effect on the nation's energy market. Global and regional outlooks will be evaluated in reference to each fuel source. This would include governments and international organizations such as the World Bank. For UCG projects there will be a greater focus on Pakistan and Australia. The research will try to analyse different sources, from think tanks, research institutes and scholars, but also from regulation, documents and presentations from entities involved in such projects.

For NPPs an economic evaluation will be carried out for the capital and operational requirements and the cost of power production. Then there will be a discussion of mechanisms and sectoral risks for financing NPPs and what barriers are there to debt financing them. This will be based on popular opinions in literature, requirement of debt financiers (such as World Bank) for risk management combined with examples of when those risks have materialized such as the Fukushima disaster. General trends will be drawn of contrasting policy decisions and their effects of various countries engaged in NPPs such as France in contrast with countries such as Germany who are phasing out nuclear power.
A similar approach will be taken for renewable energy production using the various examples such as the Three Gorges dam as economical and technical case studies. As all renewables share core general risks they will be explained individually in light of the literature present in its context and then delve deeper into risks associated with each type of renewable fuel source in context with the aforementioned projects. There will then be an analysis of how these risks were mitigated and how financing was secured by these projects through documentation of organizations such as the World Bank or Cititbank. It is a well-known fact that after the Paris agreement the world has begun an earnest move towards renewable energy. The last section will discuss incentives given by governments to power producers to conform to the trend favouring renewable energy projects with Germany and China in the forefront.

Gas power generation technology is well documented in terms of economic and technical feasibility. Natural gas power production is the oldest transitional method of power production due to the fact it is more environmentally friendly than surface coal gasification and furnace oil plants. While it cannot compare to NPPs and renewables in terms of environment it is the most dominant and economical method of power production in terms of ensuring energy security while being the least harmful to the environment as a fossil fuel. A comparative analysis of the E.U, U.S, China, and India will be done in terms of factors affecting LCOE. Pakistan's average power generation cost through natural gas power plants will be used for comparing economic feasibility especially to UCG. There will be a discussion on risk factors and how they have been dealt with over time for such projects by core principle of project financing with reference to Gulf P.D plant and Himariyah plant. There will be an analysis on the trends tightening of regulation on natural gas projects due to policy aims to cut emissions yet it great demand to replace other fossil fuel generation.

Finally, similar exercises will be carried out for UCG projects in Pakistan to determine whether this method can produce cheaper power. As these projects are relatively new in commercial terms the financing has been either equity or mostly government sponsored. On the basis of the requirements of project financiers (established through literature) sectoral risks will be identified and how those concerns may be dealt with (principal of which is the aspect of new technology). Lastly an analysis of the Chinchilla UCG project controversy to determine public risk and environmental impact. This analysis would be a helpful guideline so as what to expect from regulatory bodies once they begun regulating UCG projects in earnest.

6.Nuclear

This section focuses on power generation through Nuclear Fissile material as a fuel source.

6.1 Nuclear Power Plant Economics

Nuclear Power Plants (NPPs) are costly to manufacture yet moderately cheap to run. In numerous areas, NPP viability is a serious challenge to non-renewable energy fuels as a method for power production. Normally, waste removal and decommissioning costs are completely included in the working/operating expenses. In the event that the social, health and ecological expenses of petroleum derivative fuels are likewise considered, the economics of nuclear power is improved in comparison.

According to a levelised (lifetime) premise, NPP is a cheap method of power production, consolidating the upsides of security, quality and emanating a lower amount of carbon based gases. Existing plants work well and are highly consistent. The working expense of this technology of plants is more competitive than practically all non-renewable fuel source contenders, with an exceptional safety from risk of working cost inflation. NPPs are currently estimated to work for a long time and significantly longer for future builds. The primary monetary risks to currently operating plants lie in competing with subsidised renewable projects or gas fired generation due to low costs associated with those projects. The political danger of higher, and nuclear fuel specific taxation increases the economic risk of such projects (Nuclear Power Economics | Nuclear Energy Costs - World Nuclear Association, 2020).

Another consideration is the framework cost of making the production from any source available to meet the actual demand of the grid. The framework cost is negligible with dispatchable sources, for example, nuclear, yet turns into a factor for consideration when dealing with irregular renewables whose yield relies upon occasional wind or sun power as fuels. When the scenario occurs that the portion of such renewables increase over a certain extent of the energy mix then framework costs heighten fundamentally and promptly surpass the real cost of power generation from those sources (NEA, 2019).

There are 4 main costs for consideration for the economics of an NPP: Capital cost which incorporates the expense of site planning, development, commissioning and financing an NPP. Constructing a NPP on a large scale takes a great many labourers, enormous measures of building materials, a great many parts, and a number of systems to manage control, power, ventilation cooling, data, communication and safety. To analyse distinctive technologies for the purpose of electricity generation the capital costs must be indicated according to production limit of the plant (for instance as in dollars per kilowatt). Next is the plant operating cost which incorporate the expenses of fuel, activity and upkeep (O&M), and having a method in place specifically designed to finance the costs associated with decommissioning and radioactive waste disposal. Working expenses may be divided into 'fixed costs' that are acquired despite power production and 'variable costs', which change according to the yield. Ordinarily these costs are shown comparative with a unit of power (for instance, cents per kilowatt hour) to allow comparison with other technologies that produce power (Lovering et al, 2016).

Thirdly we have external costs. The guidelines that control nuclear power commonly require the plant administrator to ensure system for discarding waste, in this manner these expenses are 'labelled' as a feature of working expenses (and are not external). Production from petroleum derivatives isn't directed similarly, and in this way the administrators of such plants don't yet internalize the expenses of GHG outflow or of different gases and particulates delivered into the ecosystem. Adding these external costs for determining alternative project options, improves the financial attractiveness of building NPPs. Finally, there are miscellaneous costs involved, such as system integration and fuel specific taxation. From a state's strategy perspective, they are as noteworthy as the real production cost, however are hardly ever calculated into examinations of various supply alternatives. Introduction of a new plant likely causes changes to the grid, and thus causes a noteworthy expense for power supply that must be recognized. This expense for enormous plants working persistently to satisfy base-load need is exceptionally little contrasted with coordinating irregular renewables into the grid. For nuclear and non-renewable energy source generators, framework costs relate mostly to the requirement for capacity to reserve power to cover intermittent blackouts, regardless of whether arranged or impromptu (Hirth et al, 2015). Taxation is a regulatory burden usually high for NPPs and has a deep impact on project economics.

In 2015 an investigation, Economic Impacts of the R.E. Ginna Nuclear Power Plant, was published by the US Nuclear Energy Institute. It breaks down the effect of the 580 MWe PWR plant's activities through the finish of its 60-year permit in 2029. It produces a normal yearly monetary yield of over $350 million in western New York State and an effect on the U.S. economy of about $450 million every year. It has directly employed 700 people, adding another 800 to 1,000 for occasional occupations during reactor refuelling and maintenance blackouts at a regular intervals of 18 months. Yearly salaries amount to about $100 million. Auxiliary work results in another 800 employments. Ginna is the highest tax contributor in the country. Working at over 95% capacity factor, it is a truly dependable supplier of cheap power. Its decommissioning before permit expiry would be incredibly expensive to both state and nation – far in overabundance of the above figures.

In June 2015 a research, Economic Impacts of the Indian Point Energy Centre, was distributed by the US Nuclear Energy Institute, examining the financial advantages of Entergy's Indian Point 2&3 reactors in New York state (1020 and 1041 MWe net). It demonstrated that they every year it earned round about $1.6 billion for the state and $2.5 billion for the country. This includes the plants contribution to its localities valued at $ 1.3 billion annually. The plant contributes through property taxation alone about $30 million to state and local councils and has a yearly salary obligation of about $140 million for the plant's almost 1,000 workers. The local, state and federal bodies receive a total of $340 million every year in taxation, and the plant's own workers have bolstered employment by 5,400 in New York state and 5,300 outside it. It likewise makes a significant contribution to grid dependability and forestalls the production of 8.5 million tons of CO_2 for each year.

The NPP LCOE to a great extent is driven by capital expenses. At a 3% discount rate, nuclear was significantly less expensive than other fuel choices, at 7% it was equivalent with coal and less expensive than CCGT, at 10% it was on par with either. At low discount rates it was a lot more economical than wind and PV (OECD, 2015). With a CAPEX of $ 6 670/kW, a CF range of 92%, fuel cost of $7/MWh, a fixed O&M $ 101/kW-year and variable O&M $2/MWh LCOE would fall at $70/MWh (2019 ATB Cost and Performance Summary, 2020).

6.2 Barriers to Financing Nuclear Power

Project financing is the cheapest capital and is relied on heavily for energy related projects. For a bank to lend to a project however there are certain risks that need to be mitigated through contracts which are construction and procurement contract, sales contract (PPA) operation and maintenance contract and a, supply agreement (fuel), (Vinter 1998). Due to the fact there is limited recourse banks are averse to financing nuclear power as the scale in terms of capital is far greater than any other power generation project and certain risks if realized can be very costly.

Construction risk is the actual economic risk which has made banks reluctant to lend. Historically there is a pattern of delay in construction due to the complex nature of NPPs which has directly resulted in increased costs (Nuttall, 2005). Unlike other undertakings there are insufficient cases for timely development and activity of NPPs which makes banks averse to taking this risk. The record would likewise matter for every particular type of technology used for NPPs.

The construction period of an NPP is considered as the term between the laying of the initial 'cement' and connecting it to the grid. Longer the construction period greater the financing cost, and in the past this has been a prevalent issue in projects. In Asia development times are in usually shorter; for example, the two 1315 MWe ABWR units at Kashiwazaki-Kariwa 6&7 in Japan, which began work in 1996 and 1997, were completed in four years, while 48-54 months is a run of the mill estimation for current NPPs. The last three South Korean reactors not postponed by cabling substitution took 51 months to construct (Nuclear Power Economics | Nuclear Energy Costs - World Nuclear Association, 2020). In Canada the Bruce NPP faced similar problems. Bruce A was cost $1.8 billion (1978) when the anticipated cost was half at $ 0,9 billion meaning there was an overrun of a 100%. Similarly, Bruce B cost $ 6 billion (1989) despite estimates of $ 3.9 billion in "dollars of the year", a half over-run (Power for the Future, 2017).

The charge on capital for development can be a significant component of the sum capital expense, however this relies upon the time frame of construction and rate of the interest charge. A 2004 University of Chicago study shows that for a construction period of 5 years the interest charges during development can amount to 30% of the general cost. When the construction time changes to 7 years the amount rises to 40% showcasing the detriment of an overrun. Investors may include a risk premium to nuclear power related interest rates having a considerable effect on financing costs.

An understanding into the extent of various components of capital expense was given by declaration to a Georgia Public Service Commission hearing concerning the Vogtle 3&4 task, in June 2014. Here, for Georgia Power's 45.7% offer, the EPC cost was $3.8 billion, proprietor cost $0.6 billion, and financing cost $1.7 billion (assuming completion time, 2016-17). The expense of conceivable postponement was put at $1.2 million every day. The sum expense of the undertaking was calculated at an approximate $14 billion. Now costs have risen by over $ 950 million due to delays. Vogtle 1 and 2 exceeded their estimates by an unimaginable 1200% (Vancko, 2012).

These risks make debt financing for nuclear projects a pipe dream at this point. In order to secure the trust of the banks multiple NPPs need to be built (of the same technology type) on corporate or government balance sheets with proven construction track time.

6.3 Nuclear Policies

Regulating nuclear power production like all other power production projects is about balancing public interest with energy security. Nuclear powers inherent advantage is its ability to provide base load power for long periods hence greater energy security. As matters of public interest go NPPs do pose a danger to public safety and public health. The Fukushima disaster was an eye-opener that despite safety precautions such disasters are possible. Due to the radioactive nature of such disasters a thorough cleanup is necessary which can be extremely expensive. In 2016 the administration quoted cost of about $75.7 billion, some portion of the general Fukushima calamity cost of $202.5 billion. The Japan Center for Economic Research, a private research organization, said the cleanup expenses could mount to some $470 billion to $660 billion (Hornyak, 2018). More recent valuations put the total economic cost at a trillion USD (Bernard, 2019).

France is a nation heavily dependent on nuclear energy as it consists of the majority of the energy mix producing 379.5 TWh out of 537.7 TWh of electricity at 70.6% of the total (PRIS - Country Details, 2020) which is the highest in the world (Nuclear shares of electricity generation - World Nuclear Association, 2020). The Nuclear Safety Authority (Autorite de Surete Nucleaire – ASN), a new regulatory body turned into the administrative power liable for nuclear safety and radiological assurance, assuming control over these capacities from the DGSNR, and answering to the Ministers of Environment, Industry and Health in 2006. It requires approval from the government before giving licenses (Sustainable Management of Radioactive Materials and Wastes Act, 2006).

In 1999 a parliamentary discussion reaffirmed three primary points of French energy strategy: secure supply (Majority of energy is imported), regard for the earth (particularly ozone harming substances) and effective methods managing radioactive waste. It was noticed that natural gas had no financial leeway over nuclear for base-load energy, while having unstable market prices. It was acknowledged that nuclear energy is not an alternative for renewable energy production and energy conservation in the long run (Nuclear Power in France | French Nuclear Energy - World Nuclear Association, 2020).

From being a net power importer through the vast majority of the 1970s, France has become the world's biggest net power exporter, with power being its fourth biggest export. It additionally has a low record of GHG emissions (Murray, 2019). Due to this energy security despite stating in the **Energy Transition for Green Growth bill**, 2014 that they would drop nuclear power to 50% by 2025 they have delayed it to 2035 while retaining the option to build more reactors (Nuclear Power – Analysis - IEA, 2020).

Germany has had a different policy approach to NPPs keen to phasing it out in favor of fossil fuels and renewables as they believe the harm to public interest is greater than the energy security provided. This has been done through highly controversial nuclear specific taxation and a phase out plan to replace the energy mix with subsidized renewables (Energiewende) and fossil fuels (Federal Ministry for the Environment, Nature Conservation and Nuclear Safety, 2010).

The costs of power for private and most businesses have risen profoundly with the implementation of Energiewende. Beginning of 2016 saw the cost for residents was over 90% over the average prices of 2000, due to a great extent to the EEG overcharge or Umlage which currently contains 21% of the sum, which with the addition of taxes results in 23% of the sum. From 2005-14 the residential cost in the U.S was lower than just the residential power price in Germany. Germany increased its power export to 60 TWh in 2015, essentially from cheap lignite and surplus wind power (windy year!). These fares have a comparative impact in neighbouring nations as in Germany, reducing the price of wholesale power which in turn reduces profits from gas generation. Subsequently German coal-fired plants keep up high CO_2 outflows. Germany's CO_2 emanations from industry and power stations have hardly lessened between 2008 and 2015, implying that the 2020 objective of 20% decrease from 2007 levels by 2020 isn't feasible.

Germany has shown that nuclear power isn’t necessary for energy security but achieving it through renewables in their current state isn’t possible either and for that reason they had to go back to using fossil fuels for periodic power generation.

7.Hydro Power

This section focuses on using the potential and kinetic energy of water rushing down from higher elevations and farming water turbines for generation of hydropower.

7.1 Hydropower Economics

While exploitation of all the world's current hydroelectric potential couldn't adequately supply the worlds energy demand, it is the asset with the best capacity to give a clean sustainable power source to areas of the world which at present have the most need. Also, when actualized as a component of a multipurpose water asset exploitation project, a hydro station can offer various side-benefits, which no other fuel source can contend with (Bartle, 2002). These resources exist over a huge geographical area and are potentially providing over 150 countries with the ability to generate power through hydro projects. The technology has been developed for decades making it reliable and efficient with an energy conversion of over 90%. The ability for this technology to produce peak load power allows for alternate applications of base load power from less flexible fuel sources. Comparative to other large scale power projects it has long plant life coupled with low operating costs although its initial capital cost is quite steep (IHA/IEA/CHA, 2000).

Using hydro resources for the purpose of generating electricity is an attractive option for renewable resources for multiple social economic reasons. As hydropower doesn't deplete or contaminate the water it uses, it leaves this crucial asset accessible for different applications afterwards. Simultaneously, the incomes created through power deals can back other usages for welfare. These can incorporate projects for drinking water infrastructure, irrigation methods for crops, flood controls and ecotourism (Yüksel, 2010).

The upfront cost of investment in hydropower are changeable according to the site, design plans and the local prices of workers and materials. The huge construction work required for hydropower imply that the expense of materials and workers assumes a bigger portion of costs comparative to other technologies for renewable fuels. Due to maturity of the technology the variation in electro mechanical costs are little. The complete installation costs for hydropower projects on considerably larger scales may extend ordinarily from a low of USD 1 000/kW to around USD 3500/kW. Be that as it may, it is more than possible that there are hydropower projects which have costs outside the given range. For example, adding hydropower function at a current dam that was constructed for different purposes (irrigation, flood control etc.) may cost USD 500/kW (comparatively low). Then again, ventures at far off destinations, without foundation for infrastructure and situated a long way from existing transmission systems, and power consumption centres, can essentially have a cost greater than USD 3500/kW (IRENA, 2012a). Transmission line losses can also become significant.

Investment costs of smaller ventures are in somewhat higher range groups and are likely to have higher expenses on average. This is especially valid for plants with capacity limits short of one MW where the particular (per kW) electromechanical expenses are likely to be greater than the prevailing investment cost. If the head of the dam and installed capacity is higher it will inversely affect the investment cost per kw of the smaller projects. Despite head size, specific investment cost has a strong effect on installed capacity and vice versa. For head sizes over 25 to 30 metres the economies of scale are modest (Kaldellis and Kondili, 2011).

The breakdown of capital cost is dependent on both scale and location. The breakdown of costs for small scale hydro ventures in developing nations mirrors the variety of hydropower ventures and their geographical requirements as both opportunities and limitations (Figure 1). The electro-mechanical equipment costs for larger scale ventures tend to be greater, contributing from 18 % to as much as 50 % of expenses. For ventures in far off or hard to access areas, expenses on infrastructure can be the major portion of total expenses (IRENA, 2012a).

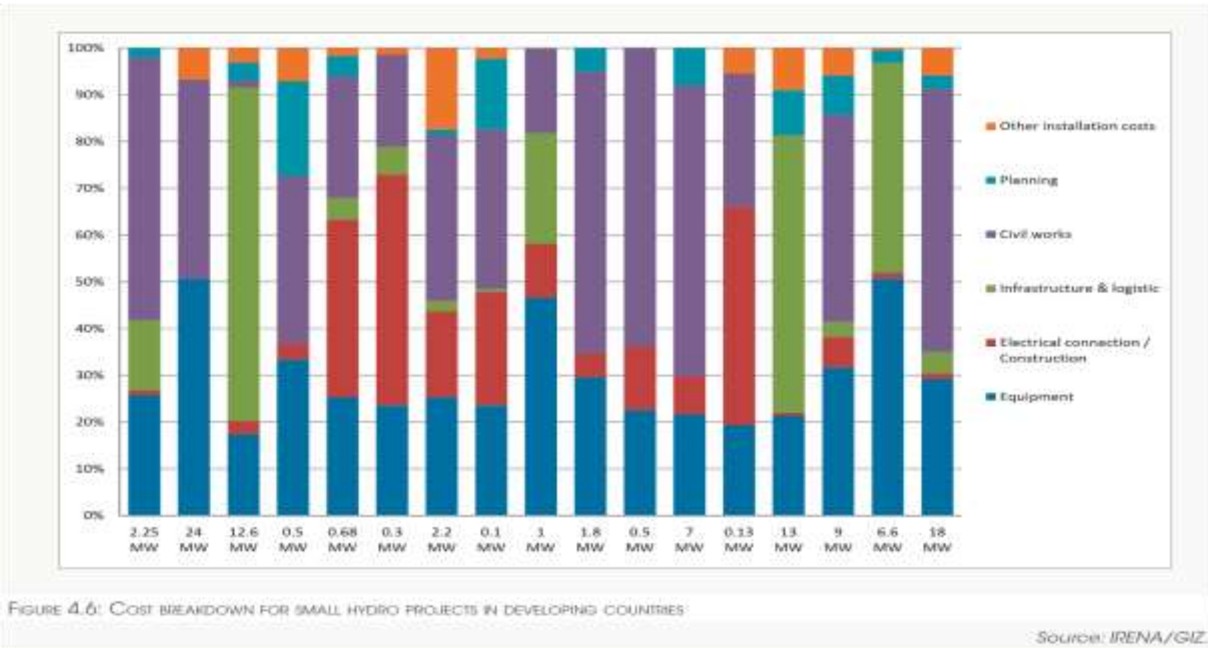

Figure 1: Cost breakdown for small hydro projects in developing countries (IRENA, 2012a)

After construction, hydropower plants as a rule require little upkeep, and activity costs will be smaller. When a progression of such plants can be introduced on a single waterway, incorporated administration would lower O&M expenses. Yearly O&M costs are regularly cited as a level of the venture cost per kW annually. Normal values go from 1 % to 4 %. The IEA accept 3% for small ventures but for large hydropower projects the figure is 2.2%, the worldwide average is however estimated at 2.5%. This will generally incorporate the renovation of electrical and mechanical gear like turbine redesign, in correspondence and control frameworks generator rewinding and reinvestments (IEA, 2010). It doesn't cover the substitution of major electro-mechanical hardware or restoration of penstocks, tailraces, and so forth. The benefit of hydropower is that these sorts of substitutions are rare and configuration have lives over 50 years for parts such as penstock and tailraces before renovation is required and 30 or so years for the electromechanical gear.

Hydropower is an appealing innovation, because of the minimal cost of the power it produces and the adaptability it can give to the grid framework. In 2018, the worldwide weighted-average LCOE of hydropower was USD 0.047/kWh – 11% lower than in 2017, however 29% higher than in 2010. Given that hydropower is an exceptionally location specific innovation, with each venture intended for a specific area inside a given waterway, the specific explanations behind this cost increment from 2014 onwards are hard to distinguish. Newer zones entail costlier development compared to the most convenient locations that have already been used. New project sites might be in more far off areas, further from existing grid framework, requiring higher connection costs, access, logistic expenses and higher development costs because of tougher terrain (IRENA, 2019c).

The global weighted-average total of installed cost of hydropower projects reduced to USD 1492/kW in 2018, 16% lower than the value for 2017 (which was similar to the 2016 value). Again these figures highly correlate with location of hydropower projects making their future trends difficult to predict. China’s projects tend to lower the global average as their installed costs are 10-20% cheaper (IRENA, 2019b).

The complete information set regarding hydropower ventures in the IRENA Renewable Cost Database for the years 2000 to 2018 proposes that the installed expenses for smaller ventures have a higher range than bigger undertakings, however for matters of deployment, the weighted average installed cost isn't substantially lower for huge ventures, aside from capacities past 700 MW. Despite the fact that the information is sparser, ventures in the range 250 MW–700 MW seem to have somewhat higher installed costs than others.

The LCOE of hydro ventures of larger scales at high-performing locations can be as low as USD 0.020/kWh, while expenses of capacity increases added in 2019 were somewhat lower than USD 0.050/kWh. For enormous hydropower ventures the weighted average LCOE of recent commissions included over the previous 10-year period in Brazil and China was USD 0.080/kWh, USD 0.120/kWh in Europe USD 0.040/kWh, around in North America and. Smaller hydropower ventures (1-10 MW) had the weighted average LCOE for new sites extend between USD 0.130/kWh in Europe, USD 0.040/kWh in China and 0.060/kWh in India and Brazil (Hydropower Costs, 2020).

7.2 Financing Hydropower

Characteristics of hydropower have been discussed in detail above however a highlight is given of those which are of key interest to financiers. These are site specific variations to projects, high proportion of civil works costs (vulnerable to local inflation), high construction risk coupled with intermittent energy production and internalization of environmental costs. The most particular element of hydro is there is no standard formula which can be applied to all projects. As in thermal power no standardization of frame sizes exists in hydro where the quantity of variables presented by the various qualities of each site preclude any normalized arrangement. Consequently, site choice and the strategy of project design, technology type and installed capacity are essentially more urgent and convoluted on account of a hydro venture than in some other type of energy generation (World Bank, 2000).

Due to this there are specific concerns with investing in hydropower. The first and foremost is the lead time for site inspection before the project can be commissioned. Commonly, under the conventional public utility strategy, the utility would have burned through 2 to 3 percent of the expense before evaluating bids for development. This cycle took years and included a slow advancement through prefeasibility, achievability and tender plan stages. The concept of development in an optimum method arose so every advantage could be taken of the site for the purpose of power generation. There is a propensity for designers to choose an arrangement that will give the minimum risks and most significant yields, regardless of the fact that the project would under-utilize the site, for instance by making a baseload run-of-river project where a reservoir undertaking may be conceivable. The organizing of most hydropower duties by and large despite everything neglects to mirror the needs of the framework, and consequently except if a developer is forced he is probably going to settle on the task that suits his goals instead of the necessities of the framework (World Bank, 2000).

The capital-focused nature of hydro implies that the possible financial injury to investors through development deferrals can be exceptional. It can be to a degree where contractual terms regarding penalties and protection are inadequate. For instance, a 300 MW venture working at a 65 percent factor will create around 140 gigawatt-hours (GWh) every month, worth a monthly revenue of $10 million. A six-month delay in operation, due to a schedule overrun of 15%, would cause a loss at $50 million. This figure would be a borderline acceptable limit for contractors in terms of liquidated damages for such a venture (Hardjomuljadi and Sudirman, 2011).

Due to the intermittent nature of water another risk is created termed as hydrological risk which may affect the project in three ways. Firstly, is the damage risk from flooding caused to the structure. The administration of flood risk during development is basically a business choice, adjusting the gradual expenses of expanding flood insurance against the likelihood and results of floods happening. This is principally a matter of risk designation between the proprietor, the contractual worker and his insurer; it would for the most part exclude the host government. Secondly unpredictability in production in the short run due to intermittent supply can cause cash flow problems. These can be mitigated through index based financial instruments and contracts (Foster, Kern and Characklis, 2015). Lastly, is a long term generation deficit caused by climate change or incorrect data as to availability of the water. There is no structure or method for mitigating such risk and loss will have to be divided amongst parties (World Bank, 2000).

The next issue is environmental risk as those are internalized in hydropower projects. On account of hydro plans the environmental matters can be complicated, and they will differ significantly between ventures. Capacity plans, specifically, will in general be delicate on the off chance that they include resettlement or the loss of rare ecosystems. In the past promoters have commonly been left to get their own clearances. This can be a tedious and costly business, and it speaks to another extra risk and certain cause of delay. The expense of ecological protection is always borne by the project (Tang, Li and Tu, 2018).

Finally, there are financial structure concerns as it is a capital intensive project requiring high up front investments. The cost based tariff profiles for hydro have a greater front cost than other projects but a low increment, which seems disadvantageous contrasted with thermal where there is a lower base expense however a lot more prominent raising component in the levy reflecting fuel and O&M. Due to this they become much cheaper in the long run, inhibiting investments in other fuel sources. It is basically over competitive in the long run while being under competitive in the short run (Canale, 2019).

Hydropower financing is a task that has traditionally been managed by the government and public sector using either concessionary finance or raising funds through credit worthiness (Hydropower financing, n.d.). Due to the increased demand of finding more sustainable methods of generating power and methods of mitigating risk, private capital is being more readily available for such projects despite core costs and risks. Institutions such as the IFC are testing new models such as scalable platform companies for a 3 GW hydropower project in Pakistan. They have invested $125 million as equity capital and provided additional project finance as well (Landy, n.d.). Another example of this trend is $200 million loan World Bank gave to China for Three Gorges Modern Logistics Center Infrastructure Project in 2017 when they refused to give a loan for the initial construction due to environmental risks (World Bank, 2017b).

7.3 Hydropower Policies

At the Kyoto protocol the mechanism of carbon credits was formalised by agreement of 170 countries after which the market mechanics were agreed upon at the Marrakesh accords. Carbon credits allow an entity to produce a prescribed amount of GHG emissions, if credits are left over they may be sold. Such agreements show that majority of the world is willing to support renewable energy production as this is a method to cap GHG emissions while providing market flexibility to do so (IPCC, 2007).

Similarly, in 2016 the Paris Agreement came into force setting goals for ecology and environment improvement with a 195 signatories demonstrating the global policy move towards renewable energy (UNTC, 2020).

In terms of specifically hydropower, China has made great developments over the past decade. The Chinese government has taken a pledge towards growing the country's hydropower generation capabilities. The Three Gorges Dam's planning started during the 1980s, as a feature of a more extensive program to utilize China's hydro assets for advancement. Chinese hydropower capacity increase became consistent through the 1990s and started to quicken exponentially in the early 2000s. The twelfth Five-Year Plan (2011–2015) put forward an aggressive objective for hydropower—30% development in capacity, from around 200 GW to 260 GW. This objective was surpassed, with China achieving a 319 GW of hydropower limit in 2015. Hydropower advancement is still a goal of the Chinese government. The thirteenth Five-Year Plan incorporates an objective of 60 GW of new hydropower limit, to arrive at an aggregate of 380 GW of hydropower limit by 2020 and 470 GW of hydropower capacity by 2025. (All figures above incorporate pumped hydro) (NEA, 2020).

Americans are additionally keen on different activities that would improve regulating hydropower and activities that would advance hydropower. This view is solid, popular and bi-partisan with larger parts of Independents, Republicans and Democrats supporting every one of these activities. In particular, they favour greater Federal investments into researching hydropower technology. Reinvestment of profits from hydropower plants to improve those plants. Hydropower developer receive market incentives on par with wind and solar developers. Easing of regulation to obtain permits quicker for relicensing or upgrading existing dams with power generation capabilities (Broad Public Support - National Hydropower Association, 2020).

A study from Carnegie Mellon University in 2015 evaluated hydropower policies on the criteria. Efficiency, Effectiveness, Equity, and Ease of Political Acceptability. Through this evaluation it was analyzed that for the purposes of P3s for hydropower projects it is more beneficial that P3s have higher regulation (Carnegie Mellon University, 2015).

While hydropower is an encouraged method of power production especially since full utilization of such sites and the cut in GHG emissions is a great contributing factor in terms of public interest, there are certain local stakeholders that oppose these especially due to resettlement issues. These issues can be seen in Balkan states such as Serbia, Albania and Bosnia which have laid plans to increase hydropower by 300%. Locals are causing delays through protests and not allowing equipment or workers to pass to the site (Salama, 2019).

There have been countries such as Cambodia which do not think that hydropower is an economical method of achieving energy security. In 2016 their Minister of Energy announced delays in dam constructions to 2020 citing that wind and solar are more cost effective and easier to build (Schneider, 2016).

8.Wind Power

This section focuses on generating power through rotational energy of wind captured through wind mills.

8.1 Wind Power Economics

The upfront capital expense (CAPEX) for wind turbines (counting towers and setup) is the primary expense in wind power. In some cases, this portion may equate to 84%. Corresponding to other renewable projects, the high capital expenses of wind power can be an issue for commercial implementation, notwithstanding the reality once the wind park has been setup the fuel cost is nil. The capital expenses of a wind power undertaking can be separated into the following classifications: Turbine costs, grid connection costs, civil works costs and miscellaneous. The portion of various cost proportion shifts by nation and undertaking, contingent upon turbine costs, site necessities, the competition of the local wind industry and the cost structure of the nation where the project is being implemented. (IRENA, 2012c).

The wind turbine has the greatest cost proportion of the complete installed cost of a wind farm. Wind turbine costs expanded consistently, seem to have peaked in 2009. Somewhere in the period of 2000 and 2002 turbine costs found the median value of USD 700/kW, yet this had ascended to USD 1 500/kW in the United States and USD 1 800/kW in Europe in 2009. Since the pinnacle of USD 1 800/kW for contracts with a 2009 implementation, wind turbine costs in Europe have declined by 18% for contracts with delivery planned for the initial half of 2010. Worldwide turbine contracts for transportation or commissioning in the second half of 2010 and the initial portion of 2011 have found the median value of USD 1 470/kW, 15% discounted from peak values of USD 1 730/kW (BNEF, 2011).

Grid network expenses can also fluctuate according to nation relying upon who bears what costs for network connection. For instance, in certain systems, it is the transmission framework administrator that bears the expense of any transmission framework overhaul required for the integration of wind farms, in different systems, the wind farm proprietor will need to pay for these expenses. Framework integration costs (counting the electrical work, power lines and the connection point) are regularly 11% to 14% of the complete capital expense of inland wind farms and 15% to 30% of offshore farms (DouglasWestwood, 2010).

The development costs incorporate transportation and establishment of wind turbine and tower, its foundation and the development of transport access and other related construction required for the wind farm. The primary foundation material for onshore is a poured concrete foundation, while offshore relies on drilled steel monopiles. The transportation and setup of the towers and turbines are likewise a significant portion of cost. Due to increases in the sizes of turbines installed has expanded the expense per wind turbine, yet transport and establishment costs have not increased in the same ratio as turbine size, assisting with diminishing the overall significance of these expenses for onshore parks. When it comes to offshore however, these expenses are a lot higher than inland and a deficiency of special purpose vessels and cranes implies that these expenses are probably not going to decrease any soon until these issues are dealt with (Junginger, 2004).

The fixed and variable tasks and upkeep (O&M) costs are a critical piece of the general LCOE of wind power. O&M costs normally represent 20% to 25% of the LCOE of wind power frameworks. A significant consideration for wind power is the way that O&M costs are not equitably disseminated after some time. They will in general increment as longer the time from commissioning has passed. This is because of an expanding likelihood of parts failing and that when failure happens it will in general be outside the maker's guarantee time frame (EWEA, 2009).

Fixed O&M costs normally incorporate insurance, organization, grid access charges and contracts for planned maintenance. In variable O&M expenses the following are incorporated; planned and unscheduled maintenance not secured by fixed agreements, and related parts and materials, and other work costs. Upkeep requirements might be little and regular (substitution of small parts, occasional checks, and so on.), or enormous and inconsistent (unscheduled fix for critical damage or the substitution of head segments). For these offshore parks O&M costs tend to be greater than for their inland counterparts because of the greater expenses associated with getting to and leading maintenance on the turbines, cabling and towers. Support costs are additionally higher because of the marine conditions and the because the failure rate is expected to be greater for certain parts (ECN, 2011).

The worldwide weighted-average LCOE of onshore wind ventures commissioned in 2018 is at USD 0.056/kWh. This figure is 13% lower than it was in 2017 and 35% lower than USD 0.085 kW/h the cost in 2010. Expenses of power from onshore farms are presently at the lower end of the non-renewable energy source cost range. The decreased cost of power for inland farms in recent years was driven by decreases in installed costs coupled with enhancements in the average capacity factor (NREL, 2018). The components driving this pattern incorporate upgrades in turbine plan and assembling; flexible global supply chains; with an increasing choice of turbines intended to limit LCOE in different working conditions (IRENA, 2019a).

In 2018, China and the United States represented the vast majority of the development in onshore wind power, with increments of 18.5 GW and 6.8 GW separately. The weighted-average LCOE of inland farms charged in 2018 in China and the United States were indistinguishable, at USD 0.048/kWh. Despite the fact that China has lower installed costs than the United States, this is balanced by lower capacity averages (IRENA, 2019b).

The worldwide weighted-average complete installed expenses of onshore parks lessened by 6% in 2018, year-on-year, tumbling from USD 1 600/kW in 2017 to USD 1 500/kW in 2018, as turbine costs kept on declining. For farms commissioned in 2018, the nation average installed costs were around USD 1 870/kW in France USD 1 170/kW in China, USD, USD 1 660/kW in the United States, 1 200/kW in India, USD, USD 1 830/kW in Germany, 1 820/kW in Brazil, , and USD 2 030/kW in the United Kingdom. The pattern towards taller turbine hubs, bigger swept zones and higher limits, reaping greater power from a similar wind asset, saw the worldwide weighted-average limit factor of onshore farms operating from 2018 increment from 32% in 2017 to 34% (IRENA, 2019c).

In 2018, worldwide offshore wind power projects totalled 4.5GW only in Europe and China. The worldwide weighted average LCOE for offshore wind in 2018 was USD 0.127/kWh – 1% lower than in 2017 and 20% lower than in 2010. The significant drivers of this decrease in the expense of power from offshore wind have been: advancements in wind turbine innovation, establishment and logistic practices; economies of scale in O&M (from bigger turbine and farm bunching); and improved limit factors from heightened hubs, better wind assets (regardless of expanding cost in deep waters seaward), and bigger rotor widths (Ragheb, 2017). The offshore wind market is still moderately slim and there is wide variety in nation specific decreases in LCOE since 2010 (EIA, 2020). Complete installed expenses of seaward wind farms have lessened unobtrusively since 2010. There is, a critical level of year-on-year unpredictability in the installed expenses of recently operational offshore parks given the generally low increase in capacity (IRENA, 2019c).

8.2 Financing Wind Farms

There are certain wind power specific risks stemming from the technology and methods of utilizing such a form of fuel for power generation. First is technology related risk product of constant innovation, can cause error in early planning with respect to asset evaluation and flexibly of sustainable power source technology (additionally affecting development and tasks) and to implementation of outdated technology, which may infer a lower productivity when contrasted with newer plants. This may cause a decrease of consumer (and political) support, possibly causing a hostile change in policy or regulation. Unpredictable and long permit approvals are particularly pertinent for offshore farms. In Germany, for example, the permit time frame can take over two years because of an appraisal of the ecological impact by the regulators (Gatzert and Kosub, 2016).

Transport, development, and commission risks predominantly centre around the initial period of the wind park project and the development time frame is commonly considered as the most hazardous stage. Dangers especially incorporate the loss of income because of start-up delays, just as the danger of damage during transportation or development of the wind farm, which, because of the high investment of capital in these tasks, such issues can turn out to be exorbitant in monetary terms. Commissioning risk can emerge from potential issues related with the integration into the grid framework. Completion and network connection issues (a "bottleneck" risk) are particularly pertinent for offshore farms, as the transportation and development measures are significantly more complicated than those of onshore projects (Rolik, 2017).

In Germany, for example, the grid framework provider had no responsibility for network integration until 2012, which suggested a genuine timing issue and significant postponement in completion. After costly issues with the offshore grid integrations, the grid administrator has been made responsible to remunerate the infrastructure provider (wind park constructor) if there should arise an occurrence of a postponed grid integration after 2012 (Apunn, 2018). Moreover, transportation liability is expanded by the essential utilization of specific transportation vehicles and methods (street vehicles, cranes, barges, "lift" vessels), including the careful treatment of parts during storage. These profoundly specific construction equipment and tools can likewise initiate a bottleneck risk because of restricted accessibility, as they might be unavailable due to limited supply and a higher demand (NREL, 2014).

One significant issue is accumulation risk, which emerges if multiple wind turbines focus on one single transfer station; in the event of harm the electricity generation of a whole wind park might be cut off. Such risk is likewise present in instances of harm to submarine transmission lines, transferring power from off shore farms to the main grid. Along the German North Sea Coast, for example, marine cables must be aggregated while interfacing offshore farms with the main grid, which is a major cause of accumulation risk (IRENA, 2019a).

The most common risk associated with renewables especially wind is that incomes of wind farms can shift impressively because of various wind speeds with a year-to-year changeability of 15–20% (in the US) contingent upon the area (solar is just 5%), where onshore farms show a higher variety than offshore farms. As obligation must be paid routinely, a base debt service coverage ratio (numerous annual obligation instalment) is required in the event that the financing includes this obligation. This is particularly pertinent because of the high capital investment in renewable ventures and the commonly high leverage ratio (up to 70–80%). These risks can be mitigated through financial instruments such as, insurance can be utilized to cover a minimum revenue in the event that the electricity generation falls under a basic limit because of inadequate wind as given by the "absence of wind cover" by Munich Re. Then again, agreements like the HDI-Gerling and KLIMA risk strategy by in Germany, for example, can be bought to acquire a fixed sum guarantee if there should arise an occurrence of unfavourable climate conditions. Volatility risks can be mitigated by the use of energy derivatives, caused by weather changeability (hedging electricity prices contingent on weather). It must be noted that the behaviour of electricity prices become more unpredictable with an increase in the ratio of renewable energy (Gatzert and Kosub, 2016).

There has been consistent development in debt financing wind power in Europe since 2011. Increase in new business models has expanded the pool of investors in wind power and opening doors to cheaper capital provided by banks, institutional moneylenders and Export Credit Agencies (ECAs). This has increased availability of cheaper debt financing such as project financing. In 2018 €26.9bn in project finance was raised: €15.9bn for the development of new undertakings and €11.0bn for refinancing wind parks. The expanding pattern of refinancing projects has been driven by enormous development in refinancing offshore parks. Of the €11bn in project finance raised for refinancing, €8.5bn was for offshore ventures and €2.5bn for onshore. The current financing structure of low loan costs have added to this pattern. Loans are being restructured to be more favourable in terms of time and prices. Proportionally non-recourse debt was much lower for offshore projects but in 2018 this pattern was turned around and 77% of all capital raised for offshore parks. As certainty develops in European wind energy, worldwide, banks keep on improving availability of cheaper capital (Wind Europe, 2019).

8.3 Wind Power Policy

Germany has a high reliance on wind energy with it providing 25% of power in 2019 and having an installed capacity of 55.6 GW at the end of 2017 (Burger, 2020). This is due to their policy movement from nuclear to renewables. The current situation in the German energy sector gives a good example of balancing public interest with energy security.

Regulatory implementation of rules had caused issues in obtaining permits which caused a decrease in expansion over the last 3 years with only an expansion of 1 GW in 2019. Around 11 GW or 2000 turbines have been stalled due to bureaucratic issues. To counter this an understanding was reached between the economy ministry (BMWi) and the 16 administrative states' governments in June 2020 which eliminated the obstructions for wind power by to a great extent leaving it to the states to choose requirements such as what minimum separation rules they need to apply. As per the German Wind Power Association (BWE), the past proposition of making a separation of 1,000 meters from local locations obligatory would have decreased potential development space by 40 percent (Amelang, 2020).

Despite these issues over the entire year of 2018, onshore parks produced more than 100 terawatt hours (TWh) of power into the grid and produced just about 17 percent of Germany's energy mix, making it the most significant renewable power source. Along with offshore turbines, which delivered around 25 TWh (4% of total) wind power altogether turned into Germany's predominant energy source without precedent (Fraunhffer Institute for Solar Energy Systems, 2019), for 2019 and in the principal half of 2020, wind power contributed about 29 percent to Germany's net electricity generation (Amelang, 2020).

The intermittent nature of wind is causing additional problems in terms of energy security. The matrix is too frail for transporting all the electricity to load centres in the south. One of the most noticeable impacts of the saturation of renewable power on the German grid is negative power costs, times when purchasers are adequately being paid to utilize abundant power. Due to an absence of sufficient framework, not every last bit of it winds up going to German clients. Rather, over production during peak time on offshore farms has overflowed to Denmark, Poland, the Netherlands and beyond. To keep neighbouring grids from being overpowered, Germany is introducing phase shifters on interconnectors, so that excess power spillage may be blocked (Deign, 2020).

During peak energy demand season however wind and other renewables are unable to meet Germany's increase in energy demand. This is especially apparent in the transport and heating sectors. This has led to an increase in natural gas electricity generation (especially since nuclear is being phased out) to meet this demand, automatically tying energy security to natural gas electricity generation. This increase in fossil fuel use has caused Germany to fall short of meeting its emission reduction of 40% from 1990 (as of 2018 it is 31%) (IEA, 2020a).

While Germany is a good example of policies where renewables especially wind energy is being used to produce clean energy while maximizing public interest the fact remains due to winds intermittent nature, policies are being implemented to ensure energy security. With the phasing out of nuclear this has led to fossil fuels as an alternate source creating a paradox by hampering Germany's ability to achieve its GHG and environmental protection targets.

9.Solar Power

Solar PV technology produces power using panels to absorb light and converting it into electricity. It is analysed as follows:

9.1 Solar PV Economics

Solar assets are accessible in each nation and both solar photovoltaic (PV) and concentrating solar power (CSP) methods can be utilized to change this solar asset into power. Solar PV can utilize both immediate and diffused daylight to make power, while CSP depends on direct daylight, confining its implementation to zones with high direct ordinary irradiance (DNI). Towards the end of 2019 total solar PV capacity stands at 578 GW, while CSP capacity is still in its early stages at 6 GW (Solar Costs, 2020).

The PV module cost is normally between a third or half of the complete capital expense of a PV framework, contingent upon the size of the venture and the kind of PV module used. Predicting change in module cost is a challenge due to the high learning pace of 22% that has been experienced in the past. With the PV market growing at such a high rate, projections of cost decreases can immediately become obsolete. A gauge of the worldwide cost of c-Si PV modules in 2008 was USD 4.05/W and this had declined to USD 2.21/W in 2010 (Solarbuzz, 2011), a decay of 45% in only two years. The pace of decrease in costs has not eased back and by January 2012 spot market and factory costs in Europe for cheap Chinese and other producers of c-Si modules had dropped to around USD 1.05/W (Photovoltaik, 2012). Spot and plant costs for c-Si modules from European, Japanese and different producers had declined to between USD 1.22 and USD 1.4/W (IRENA, 2012b).

The balance of system expenses and establishment involve the rest of the capital expenses for a PV framework. The BOS costs generally rely upon the specifics of installation. It can be as low as 20% for utility scale PV plants (for a straightforward grid connected framework) or as high as 70% (for an off-grid connection), with 40% being illustrative of a standard utility-scale ground-mounted framework (IEA PVPS, 2009). For private and small frameworks, the BOS and establishment costs attribute to 55% to 60% of complete PV framework costs. The normal expense of BOS and establishment for PV frameworks can range from USD 1.6 to USD 1.85/W, contingent upon whether the PV framework is roof top or ground mounted, and whether it has a tracking framework (Hard, 2010 and Photon, 2011).

These BOS expenses are divided in to 6 key parts. The inverter is one of the key segments of a PV framework. Inverters are the essential parts of a PV framework and normally represent 5% of installed framework costs. Mounting structures and racking equipment segments for PV modules are ordinarily pre-designed frameworks of aluminium or steel racks. They represent roughly 6% of the capital expense of PV frameworks (Mehta and Maycock, 2011). Mounting structures fluctuate contingent upon where the PV frameworks are sited. Combiner box and other electrical parts incorporate all residual establishment costs including combiner boxes, wires/conveyors, conductors, information observing frameworks, and different equipment. Site arrangement and framework establishment are significant segments of the BOS and establishment costs. They incorporate site planning (rooftop or ground-based), any physical development works (for example electrical foundation), establishment and integration of the framework. Work costs make up most of the establishment costs, and differ by task and nation. Framework plan, administrative expenses incorporate framework structure, permits, financing and management costs. These expenses depend altogether on the nation where the project is implemented. Power storage frameworks for off-grid PV frameworks empower power use around evening time or during overcast periods (IRENA 2012b).

As 2019 ended, over 580 GW of solar PV frameworks had been introduced, around the world. This speaks to a 14 times development for the innovation since 2010. Around 98 GW of recently introduced frameworks began operating by 2019. The new capacity increments were the greatest among all renewable power fuels in that year. Development in 2019 was driven by capacity increments in Asia, with the area contributing to an approximate 60% of the projects that year. Improvements in that area were driven by China, India, Japan and the Republic of Korea, altogether introducing 47.5 GW of PV limit during 2019 (IRENA, 2020a).

Advancement of related technologies is the major reason for these decrease of costs. Latest module cost decreases are firmly identified with advancements in module producing and to productivity gains related with new cell designs. In solar PV modules, higher efficiencies make an interpretation of in to smaller area that can produce a unit wattage. Higher module efficiencies hence lessen module costs per watt and those BOS costs identified with the location of the solar establishment. Cost decreases have additionally been accomplished in the solar PV module fabricating supply chain. This will then translate into lower expenses per Watt (IRENA, 2018).

The worldwide capacity weighted-average installed cost of ventures in 2019 was USD 995/kW (18% lower than in 2018 and 79% lower than in 2010). During 2019, the fifth and 95th percentile range for all ventures tumbled to a range between USD714/kW and USD2 320/kW – numbers 10% and 16% lower than in 2018. As time has gone by, cost structures have kept on developing in an expanding number of sectors and contrasted with 2010, the fifth and 95th percentile numbers were 79% and 71% lower. An expanding number of cheaper cost projects in India prompted weighted average total installed expenses of USD 618/kW in 2019, around a fifth lower than in China. Somewhere in the range of 2010 and 2019, installed costs have declined somewhere in the range of 74% and 88% in business sectors where verifiable information is accessible back to 2010 (IRENA, 2020b).

The worldwide weighted average limit factor for new utility-scale solar PV expanded from 13.8% in 2010 to 18.0% in 2019. This was determined by the expanding implementation in sunnier areas. Subsequent to expanding consistently somewhere in the range of 2010 and 2018, the limit factor is settling around 18% (IRENA, 2020a). The improvement of the worldwide weighted-average capacity factor is a consequence of numerous improvements occurring simultaneously. Higher capacity factors as of late have been driven by sunnier project areas, the expanded utilization of tracking systems in the utility-scale portion in larger markets and a number of different variables that have made small differences (e.g., increasing system efficiency) (Gulaliyev, Mustafayev and Mehdiyeva, 2020).

Lately the O&M expenses of solar PV utility parks have started to decline. Notwithstanding, in specific business sectors, the portion of O&M costs in LCOE has ascended, as capital expenses have fallen quicker than O&M costs. In the time of 2018-2019, O&M quotes for utility-scale parks in the US are accounted at between USD 10/kW and USD 18/kW every year (Bolinger et al., 2019; EIA, 2020; NREL, 2018).

The quick decrease in installed costs, expanding capacity factors and decreasing O&M costs, have added to the exponential decrease in the expense of power from solar PV causing its financials to improve proportionally. In 2019, the lowest average LCOE for a commercial park up to 500 kW could be found in India and China, at USD 0.062 and USD 0.064/kWh, individually. Somewhere in the range of 2017 and 2019, the LCOEs in these business sectors have fallen 12% and 26%. Since 2017, these two business sectors have been more serious as far as the LCOE of commercial frameworks, after reducing what was the reference LCOE benchmark for business frameworks -Australia. This is in spite of a 20% LCOE decrease in the Australian market somewhere in the range of 2017 and 2019. The business sectors with the most elevated LCOE in 2019 were the U.K and Massachusetts, at USD 0.187/kWh and USD 0.186/kWh, separately. The general commercial PV LCOE market range declined from between USD 0.259 and USD 0.625/kWh in 2010 to USD 0.062 and USD 0.187/kWh in 2019 – a decrease of somewhere in the range of 70% and 76% (IRENA, 2020b).

9.2 Solar Financing

Financing solar undertakings has risen up out of a few autonomous and interlinked methods of financing practices, including conventional project finance, tax equity partnership, structured leasing and secured lending, financing from investors in early phases, joint ventures, and getting and flipping of ventures that is a common practice amongst a wide assortment of solar industry members. However, at its centre, solar project finance generally shares much with wind venture finance just as typical energy financing, the exceptional issues related with solar ventures bring about a profoundly particular practice. This can be seen with the lower costs hence risk (technical) of building and maintaining an appropriately sited solar park, the dependence on enormous volumes of mass-delivered segment parts accessible in a worldwide market, and the ability to use rooftops and community gardens to create a distributed generation project set solar tasks apart from other power producing ventures (Mertenes and Nussbaum, 2017).

Despite the fact that specific regular structures exist through the market, it is correct to state that no two arrangements are equivalent to one another. It is likewise normal for venture ownership to change hands a few times during development before sponsors look for full-scale financing, or for the venture to look for financing time and again. All solar industry members are very much encouraged to stay vigilant for issues that may affect a projects capacity to get financing, paying little mind to where in the pipeline or life cycle the venture is (Mazzucato and Semieniuk, 2018).

Executing on a solar venture finance bargain isn't just deciding on financial structuring but instead includes an examination of genuine property rights, development and construction contracts, hardware guarantees, PPA and interconnection arrangements, managing cash, ecology impact, regulatory issues, and, tax liabilities. In spite of the fact that the pervasiveness of debt financing has been eclipsed in the solar business by tax equity, most solar undertakings are financed sooner or later in their life cycle by some form of debt. Usually solar undertaking designers, patrons, and proprietors don't themselves have available taxable income sufficiently adequate to exploit the advantages from the ITC. Financial institutions and companies with federal tax burdens in the U.S have begun to invest in solar projects as equity owners. Crafted by organizing transactions to allow these investors with high tax liabilities to coordinate with qualifying solar undertakings and guarantee the advantage of the ITC is the focal capacity and challenge of solar tax equity financing (Mertenes and Nussbaum, 2017).

For countries such as India and Morocco public financing has been integral to building solar farms. The utilization of solar farms all over India has fundamentally de-risked the activity of gaining land and integration into the grid (World Bank, 2019). The solar park program aims to create a capacity of 40 GW of solar power. In 2017, World Bank and India declared the marking of a US$100 million bundle of financing to give sub-loans to empower provinces to develop different solar parks, generally under the authority of the Ministry of New and Renewable Energy. The Shared Infrastructure for Solar Parks Project which is being financed using US$75 million credit from the International Bank for Reconstruction and Development; coupled with US$23 million concessional advance and US$2 million award from the CTF. The initial solar farms benefiting are in the Rewa region of Madhya Pradesh, with 750 MW focused on installed capacity (World Bank 2017a). As of June 2018, the state had affirmed 45 solar farms over 22 provinces, adding up to 26 GW of arranged capacity (MNRE, 2018).

9.3 Solar Policy

As Germany and India have recently done great development in solar PV, Germany as part of their broader transition to renewables and India to capitalise on its solar potential below is an analysis focused on how they have developed this fuel while balancing public interest and energy security.

One of the leading nations to implement utility scale solar PV was Germany. It was, in 2004, the main nation, along with Japan, to arrive at 1 GW of combined installed PV capacity. After then this fuel source has been becoming significant because of the nation's feed-in tariffs for renewable fuels, introduced by the German Renewable Energy Sources Act, coupled with innovation decreasing costs. Costs of PV frameworks diminished over half in time since 2006 (BSW Solar, 2011). By 2011, solar PV gave 18 TWh of Germany's power, or about 3% of the total (German Solar Power Output, 2011). That year the national government set an objective of 66 GW of introduced solar PV limit by 2030, (Germany Reducing Incentives for Solar Property Investment, 2010) to be reached with a yearly increment of 2.5–3.5 GW, and an objective of 80% of power from renewables by 2050.

The main method for these developments are FITs spreading costs amongst consumer's overtime. The goal for 2030 is to reach a 66 GW capacity. This has been coupled with an effort (2007 onwards) to increase these limits by 30-50% annually. The nation recently recommended to remove the subsidies on FITs up to 30%, restricted the compensation on power created, and disposed of the self-utilization reward. The impact is to show from January 2013 yet apply to all introduced by March 9, not April 1 despite public opinion. (There would be another cut of 15% in the past FIT structure) (Montgommery, 2012). That implied that clients were in actuality furrowing cash into enormous benefits for the progressing solar industry. Legislators have become concerned that such policies are getting hurtful for Germany. The quick pace of roof panel establishment has converted into significant expenses for service organizations and clients. Also, overcapacity and rivalry from less expensive solar modules, delivered in Asia, imply that numerous local organizations cannot contend. Beginning from May, the FITs will be diminished month to month by 0.15€ cents/kWh for every new framework. All new smaller frameworks will be compensated for 85% of the power delivered; medium-sized and enormous frameworks will have a return of 90%. Be that as it may, German FIT will require for utilities to purchase power from solar farms of 10 kW or lesser for 19.5 Euro pennies per kilowatt hour (kWh) on a 20-year contract. Bigger farms (over 1MW) will get simply 13.5 Euro pennies per kWh (Sahu, 2015).

The state of India declared a grant of Solar Incentives around the end of July 2015. The decrease in the pace of capital subsidies and accelerated depreciation from 30% to 15% and from 80% to 40%, has been fruitful in drawing in the solar farm developers to increase farm installations. Now that certificates are granted due to renewable fuel usage (empowering intrastate energy exchange), guaranteed PPAs (ensures the acquisition of produced solar power), and incentivising net metering (guarantee monetary advantages to the plant proprietor), installed capacity expanded by 45% in 2015–16 alone when contrasted with a year ago (Tarai, 2018).

Germany currently has a total consumption share of 8.6% for solar PV while India's is 7.5% (IEA, 2020b). The installed capacity in Germany is 49, 200 MW while in India it is 42, 800 MW (IRENA, 2020a). Germany due to its growing reliance on intermittent renewables is suffering from grid issues discussed in Wind Power Policy, however solar is power is less of a contributing factor. It must be noted that installed capacity of solar PV is relatively low compared to other fuel sources due to lack of storage and small scale implementations. The technology is still in the process of development and it cannot be said for certain to what extent solar PV can provide energy security once the innovations saturate and currently is deemed to have higher potential than other renewables due to low capital costs and flexibility of installation. The power production from solar is also less intermittent than its hydro and wind counterparts. Solar PV shares the same benefits as other renewable fuels as it is ecologically sound and carbon free.

10. Natural Gas Power

Natural gas is the oldest bridge fuel in terms of shifting to a cleaner and low carbon society. This study analysis is as follows:

10.1 Natural Gas Power Economics

In majority of industrialized nations, stations are constructed for the purpose of generating power for multiple consumers. These facilities or station generators, are frequently situated in distant zones, a long way from the point of utilization. Costing is the core station generation economics. As with other fuel utilization infrastructures, construction and operation of these stations involves fixed and variable expenses. The fixed expenses are generally direct; however, the variable expense can be complex due to a variety of factors. The fixed expenses of producing electricity are mostly capital expenses and land. The capital expense of building station generators, vary depending on locality, generally because of labour costs and "regulatory costs," which incorporate activities including obtaining construction site grants, ecological impact approval, etc. Building a power station can take an enormous amount of time. An example is, Texas (where building power plants is moderately simple), commission time can be as short as two years. In California, however constructing a power plant is considerably more troublesome (because of more stringent regulations), commission time can surpass ten years. Working expenses for power plants incorporate fuel, maintenance and labour costs. Not at all like capital costs which are "fixed" (don't shift with the degree of yield), a plant's total operating expense relies upon how much power the plant produces. The working cost needed to create each MWh of power is alluded to as the "minimal cost." For fossil fuel power plants, the main operating cost is the expense on fuel. For renewables, fuel is commonly free (maybe except for biomass power plants in certain situations); and the fuel costs for NPPS is quite low (Basic economics of power generation, transmission and distribution | EME 801: Energy Markets, Policy, and Regulation, 2020).

The capital expense of natural gas plants is dependent on the type of plant being constructed and operated. The costs of a gas fired plants using steam for generation are comprehensively identical to a coal-fired plant, despite the fact that there will be less operational expense due to fuel costs and the gas-fired plant won't require either a sulphur scrubber or a residue removal unit. The steam turbine and heat exchanger will be the prevailing costs (Botero, 2009).

The capital expense of gas is highly dependent on the cost of the turbine generator. These machines are technologically advanced and the quantity of makers is restricted yet the market is worldwide, inducing competition. Moreover, these are basically off-the-rack segments that are conveyed from an industrial facility for all intents and purposes prepared to be set up and operated. This implies the time needed to manufacture a gas turbine power plant is shorter than, for instance, a coal-fired plant. These elements have ensured that gas turbine combined cycle plant technology can be used to build larger capacity plants while being relatively cheaper than other technologies and fuels (Breeze, 2016).

In 2001 the capital expense of a combined cycle plant was $533/kW. The overnight cost rose gradually to $563/kW in 2003 preceding falling back to $550/kW in 2007. In 2009 the expense was assessed to be $877/kW and has risen consistently since, coming to $942/kW in 2015. The expense of a combined cycle gas turbine has demonstrated a comparable pattern, with an expense of $440/kW in 2001, ascending to $639/kW in 2015. The expense of a plant with carbon sequestration was put at $992/kW in 2005, 92% higher than a plant without carbon sequestration. In 2015 the assessed cost of this plant was $1845/kW, 96% more costly than the plant without carbon disposal systems (Breeze, 2016). By method of examination, US EIA Annual Energy Outlook for 2015 assessments cost of a coal-fired plant to be $2726/kW and that of an inland wind park at $1850/kW.

The expense of the power the plant produces relies fundamentally upon the expense of gas. This has indicated a chronicled inclination to change. At the point when cost of gas fuelling the plant is low the expense of power from a gas fired plant decrease proportionately. Gas fired plants become uneconomical if these costs increase and there are approved models in many developed nations of combined cycle plants that had to be closed down in light of the fact that they can't produce power economically due to shift in gas price (Boyce, 2012). The expense of gas relies upon accessibility and in the United States, the shale gas revolution has prompted a fall in gas costs, making gas-fired power incredibly cheap. The yearly normal expense of gas to US electric utilities is somewhere in the range of 2003 and 2015 was between $5/GJ and $6/GJ toward the start of the period and crested at near $9/GJ in 2008. Notwithstanding, by 2015 the expense had tumbled to under $4/GJ (PRI, 2015).

In different places the world fuel costs are commonly higher. If average expenses are compared in 2014 the U.K had twice the costs of gas power than the U.S. In Japan this form of power production was even more expensive with an approximate difference of 400% than the U.S (including transport costs. On average other areas have a higher cost associated with gas power than the U.S. (Breeze, 2016).

The IEA World Energy Model (2019) gives a good insight into various economical inputs based in the regions of U.S, China, E.U and India of different economical inputs to determine current value of natural gas power (CCGT technology). In 2018 the figures are as follows:

Country	**Capital Cost ($/kW)**	**Capacity Factor (%)**	**Fuel & O&M ($MWh)**	**LCOE ($/MWh)**
United States	1000	50	30	50
China	560	50	75	90
E.U	1000	40	60	90
India	700	50	80	95

Figure 2: LCOE inputs Natural gas (IEA, 2019)

This data is a clear indication of dominant fuel costs are for NGCCT power production in terms of total costs. China and India despite having lower capital costs have a much higher LCOE than the U.S due to the fuel and O&M difference. This is quite different from renewable and nuclear costs division (as discussed in relevant sections) which are highly capital intensive yet have low to negligible fuel costs by proportion. This is an indication that NGCCT is only viable in the long run in countries with ample recoverable reserves of natural gas. Shale gas sources have increased the potential of this hydrocarbon power generation method by introducing a new source of gas reserves. If other nations exploit these in the same manner as the U.S they can potentially lower the fuel costs enabling longer cheaper usage of this technology until renewables become cheaper and more efficient.

10.2 Natural Gas Power Financing

Natural gas power generation has existed for decades and is one of the most common methods of producing electricity worldwide. In the U.S in 2019 1582 billion kWh was produced through natural gas station compromising 38.4% of power generation which was the highest amount of power produced by any fuel that year (EIA, 2020c).

Gas has been key in shifting the energy mix to a lower carbon setting in the past half century. Power generation has been the greatest use of natural gas. During the 1973 era when the first oil price shock happened 25% of world power was generated by burning oil; in 2018, it represented only 3 percent. Even though gas was not considered a serious fuel for generating power until the 90s it rose from 12% to 23%. Over the recent thirty years, there have been numerous instances where oil-to-gas conversion has resulted in lower discharges of CO_2 and ecological contaminations. It must be noted that due to the fact that the conversion has mostly occurred this benefit has peaked hence the turn to renewable power (the one exemption is the Middle East, where oil despite everything made up a fourth of the area's power generation in 2017) (Tsafos, 2020).

Fuel price risk is the major risk in gas power generation. Renewable fuel sources have the advantage of being immune to fuel price risk which is a major factor in natural gas power. Against the setting of progressively unstable gas costs, renewable fuels, which thorough attributes are safe to gas fuel price risk, give a possible financial advantage. This advantage can be seen by the fact that renewable energy is sold under fixed price contracts unlike many gas power contracts (Bolinger, Wiser and Golove, 2006). The change in fuel cost and its effect on the LCOE can be observed in the section above. It must be realized however that the industry has many years of dealing with this issue and investors and financiers have become comfortable with investing into natural gas power (using mitigatory instruments) despite this issue.

A new form of risk has emerged over recent years for natural gas investors that of stranded assets due to availability of cheaper renewable alternatives. While looking at LCOE just recounts to part of the story, the financial aspects for renewable fuels stay convincing when comparisons are made between portfolios of renewable and gas power generation (due to environmental costs). NV Energy's ongoing acquisition of 1,200 megawatts (MW) sun powered and 580 MW of four-hour battery capacity as of now beats new gas on cost. NV Energy paid \$20/MWh for sun powered and \$13/MWh for battery storage to move 25% of power produced in a day, bringing about an expense of \$33/MWh per MWh conveyed (counting government tax credits). Gas power plants worked by rate regulated utilities after 2020 will not be able to balance out capital expenditures for which clients will probably be paying until 2045 or 2050 expecting controllers allow utility solicitations for cost recuperation. There is a possibility that cheaper renewables take over gas plant market shares while they are still productive. Due to public pressure regulating authorities may have to either reduce or stop cost recovery through customers for newer and underutilized plants (Holzman and O'Boyle, 2020).

Despite these issues, due to certainty and provision of energy security that natural gas power provides, it has access to cheap capital from financial institutions. U.S investment trends show that utility investors are likely to have spent $ 1 trillion on gas plants and fuel by 2030 (O'Boyle, 2020). A report published in 2018 by the Asian Development Bank shows the president of the bank’s recommendation to help finance the Riau Natural Gas Power Project in Indonesia. The president recommended approval of firstly a loan of up to $70,000,000 from ADB’s ordinary capital resources. Secondly a B loan of up to $82,000,000, and thirdly a partial risk guarantee for the B loan covering up to $77,900,000 of principal plus interest and guarantee fees from ADB’s ordinary capital resources, to PT. Medco Ratch Power Riau for the Riau Natural Gas Power Project in Indonesia in accordance with terms, conditions and policy (Asian Development Bank, 2018). The Japan Bank for International Cooperation released a press release in 2019 where they stated that they would project finance a Gulf P.D NGCC plant (2500 MW) in Rojana Industrial Park, Rayong Province, Thailand. They are providing financing of $208 million. This project is co-financed by Asian Development Bank (ADB), Export-Import Bank of Thailand (EXIM Thailand), Mizuho Bank, Ltd., Sumitomo Mitsui Banking Corporation, Sumitomo Mitsui Trust Bank, Limited, DZ Bank, Oversea-Chinese Banking Corporation Limited and regional banks in Thailand with finance total amounting to $1366 million (Japan Bank for International Cooperation, 2019). The IFC in recent months approved a loan of $342 million for a 390 MW Atinkou power project in Africa (NS Energy, 2020). This clearly shows that institutions are willing to invest in natural gas power despite stranded asset risk.

10.3 Natural Gas Policy

Natural gas power generation is currently the bridge fuel between fossil fuels and widespread renewable generation. This is due to the fact that it is the least pollutant energy source in balance with the most economical and reliable. That being said without carbon sequestration plants do emit GHGs which are harmful to the environment. That coupled with the fact that natural gas is a depleting resource shows that the energy security it provides is not infinite and the public interest is the best available option not the best absolutely.

Following three level years, worldwide energy related CO_2 discharges continued increasing in 2017 and 2018, speaking to a hazardous detachment with worldwide atmosphere objectives. Plainly exchanging between unabated utilization of petroleum derivatives, alone, doesn't give a drawn out response to environmental change, yet there can regardless be critical CO_2 and air quality advantages, in certain nations, areas and time spans, from utilizing fuels with a lower discharge. Since 2010, coal-to-gas exchanging has spared around 500 million tons of CO_2 - an impact proportional to putting an extra 200 million EVs running on zero-carbon electricity and about over a similar period. In the United States, the shale transformation has dramatically increased gas supply and decreased costs. Both state and federal policies have driven gas upwards ratio wise into the energy mix while pushing out coal. Since 2010, natural gas has the greatest share increase in the energy mix. In China, in order to improve air quality, policies have been implemented that have led to a rise in gas demand. Gas is mainly used instead of coal for industrial and private boilers in numerous urban zones, yet the shift for power generation is not yet clear. There has been moderately less change in Europe since 2010, with the prominent exception of the United Kingdom. Anyway the present blend of low gas costs and higher CO_2 costs in the European Union is giving this movement a greater push regionally. In India, gas at present has a little portion of the energy mix. Enormous levels of shift have been kept down due to lack of infrastructure, supply and capital (IEA, 2020d).

Germany has relied on natural gas power to phase out both nuclear and coal while supplementing renewable energy production. Germany has guaranteed a moderately significant level of gas supply security, notwithstanding a weighty dependence on imports. Despite the fact that the German government energy policy is centered around an enormous buildout of renewables, the elimination of both nuclear and coal power will proportionally expand Germany's interest for gas power, including as a reinforcement fuel for renewables. The demand uptick will increase Germany's currently high dependence on imports further. Besides, while Germany's own production of gas is little and declining, its gas imports from European sources are likewise set to fall in the coming years, particularly from the Netherlands, where production from the Groningen field is declining and due to completely end by 2022. Therefore, security of gas supply is a top priority for the government (IEA, 2020a).

Natural gas power is the fuel source that has achieved the best balance of public interest and energy security. For this reason, despite global policies against fossil fuels, the ones for natural gas are mostly positive in the sense that they have increased its share of the energy mix. It is even preferred by some countries over nuclear. It is likely to be developed further despite the risk of stranded assets until renewables become more cost competitive over a wider geographic region.

11. Underground Coal Gasification Power

Power production through Underground Coal Gasification (UCG) technology incorporates burning low grade coal underground and using the byproducts called syngas in order to generate electricity using conventional thermal power generation concepts.

11.1 Underground Coal Gasification Economics and Finance

Overall coal utilization is relied upon and usage will increment by 55% by 2,030 as developing countries build up their coal supplies; underground coal gasification (UCG) is required to be a significant player on the grounds that almost 85% of discovered coal deposits are difficult to reach utilizing surface mining methods (UCG Association, 2014). In its most straightforward structure, UCG includes two wells: one to infuse the oxidant into the coal seam, typically at depths>100 (m), and another to separate the subsequently produced gases, which are referred to on the whole as syngas. UCG offers a few points of interest over conventional mining and thermal coal power technologies that make it more secure, cleaner, and more practical; they incorporate the accompanying: no miners required, all coal is gasified underground, which diminishes the ecological impact of the UCG plant by ending the requirement for a surface gasifier, accordingly disposing of related residue discharges and need for coal transportation, storage and handling costs. All syngas created goes to the surface at a pressure close to the hydrostatic pressure of the UCG well, which allows easier conversion into a variety of products while helping implementation of numerous carbon dioxide (CO2) sequestration technologies (Pei, Korom, Ling and Nasah, 2014).

The cost of power is to a great extent controlled by the fuel cost. The outcomes showed that, for the simple case without CCS, UCGCC was equivalent to PC and NGCC and, with CCS, UCGCC power cost was essentially lower than PC and similar to NGCC. UCGCC had the option to give CO_2 at a lesser cost on the carbon use market. Likewise, power cost of UCGCC is substantially less dependent on fuel cost than the others. This means that despite changes in fuel costs profitability of UCGCC remains stable. In contrast with IGCC, UCGCC essentially decreases cost in gasifier and coal acquirement. The generation cost of UCGCC is affected by the coal seam thickness and depth. The expense was inside the range of NGCC costs. Thicker the coal seam greater the competitiveness of UCGCC. The thicker the coal bed, the bigger the gasification reactor can be. In this manner, one pit can give more coal to gasify, and less new wells must be drilled down every year. The greatest Operation and Maintenance (O&M) cost is the drilling which is reduced due to this method (Pei, Barse and Nasah, 2016).

Results of various reports have introduced consequences of underground coal gasification tests directed in Poland at Central Mining Institute in an ex situ reactor (Janoszek et al., 2013), which demonstrated concern of negative impact of UCG production on the environment, including primary ecological issues like underground water contamination (Smoliński, Stańczyk, Kapusta and Howaniec, 2012). In ecological and cost examinations of UCG innovation, ecological and financial advantage, come about because of the utilization of UCG, related with dodging certain costs and ecological effect of extricating and moving coal, must be underscored. CO2 discharge from syngas ignition and power utilization had the biggest effect on nature. The examination of UCG innovation eco-proficiency empowers evaluating impact of given factors on ecological execution and cost effectiveness. Subsequently it is conceivable to show standards affecting profits of UCG ventures. Accessibility of framework to create power, and thickness of a coal seam have the biggest impact on underground coal gasification innovation Eco efficiency with the shaft less strategy. Different components impacting Eco efficiency are costs of CO2 discharge allowance (Burchart-Korol, Krawczyk, Czaplicka-Kolarz and Smoliński, 2016).

Now however the primary preferences of the strategies to produce UCG incorporates decrease of two significant GHGs to be specific methane and carbon monoxide. All the innovations for methane capture are valued nowadays, as methane is a discharge gas which has up to 20-times more prominent impact in the environment than CO2 (Schiffrin, 2015). Current application of CBM and UCG advancements is likewise focused on utilization of CO2. On account of UCG innovation, no discharge gas is utilized, yet bringing UCG and CBM advances together is fascinating, as well as using the cavity for the storage of by-product CO2 (Škvareková, Tomašková, Wittenberger and Zelenák, 2019).

In 2018 a handbook was published by Dr. Samar Mubarakmand outlining the most productive method for producing power through UCG technology and the costs associated with it (using 2018 figures). The project was for a trial power plant producing 8,000 kW which could produce continuous power using 16 Gensets of 6,400kW. The cost of 16 Gensets (400kW each) was $ 6.2 million. The installation and labour cost amounted to an approximate of $ 656 thousand. A 2.5 MW co-gen plant was added for an 18% enhancement in production costing $ 2 million. This plant had an operational life of 15 years. Using an air injection method, it would have a power output of 12.272 MW/h. using 4 faces of coal. The captive power amounted to 2.64 MW/h. This made available 153,464 kW/h electricity for sale per day at a cost of $ 0.050/kWh. The cost of 1 mmbtu of syngas was $5.00.

It was recommended by him however to use an oxygen swing machine, one for three faces injecting 60% oxygen enriched air into the wells for combustion. Despite having a higher CAPEX it improved production enormously. It allowed production of 284,160 kW/h daily. The cost of electricity produced dropped down to $ 0.030/KWh. The cost of 1 mmbtu of syngas was $2.94.

The cost of power through natural gas production is $ 0.046/kWh (Fatima, 2019) while the cost of 1 mmbtu of gas is $ 6.14 (Domestic Rates | Sui Southern Gas Company Limited, 2020). The UCG project had the additional benefit of GHG sequestration. After the heated gases are passed through the HRFG for co-gen the cooled by product CO2 is redirected into the cavity at minimum cost reducing external cost with minimum investment (Mubarakmand, 2009). While these financials are of a specific project in Pakistan they have shown much promise in terms of cost effective power generation with a minimum ecological impact. Similar progress is being made in UCG power generation projects across the world such as in China (ZOU et al., 2019). The byproducts of syngas power generation can be further utilized in the chemical industry for the production of diesel, fertilizers etc. giving it an additional economic benefit (Mao, 2016).

As UCG is in a pilot phase with no commercial projects for power production, it is unlikely to be financed by institutions and banks until a track record of successful projects can be set. Current projects for production of syngas are largely government funded. In this section the principles of project finance will be analysed in light of UCG projects to determine their theoretical appeal to investors. Principles of project finance are used as it is a limited recourse form of financing and has high qualification standards.

Project Finance can be portrayed as "financing the development or exploitation of a right, natural resource or other asset where the bulk of the financing is not to be provided by any form of share capital and is to be repaid principally out of the revenues produced by the project in question" (Vinter 1998). An SPV is set up by the sponsor company to manage and own the project. A consortium of banks would loan to the SPV so that they may buy or build the assets generally a power plant. Incomes produced are utilized to reimburse debt obligations. A core advantage is as the company sponsoring the SPV has a different legal identity, its liabilities are limited to only its equity in the SPV. Companies prefer using SPVs for the sole purpose the bank has limted to no recourse in terms of the sponsor companies. Project finance likewise gives the support organization a choice to leave (Esty and Kane 2010).

The financial structure has two purposes which it is to fulfil simultaneously. These are to provide returns for investors while generating enough cash flow that credit can be paid off on the agreed upon time. Banks giving the finance require confirmations that the income will remain reliably certain and consequently key dangers to that are lawfully partitioned among parties that have the ability to manage them. The bank will insist that the following contracts have been entered into by the SPV before approving the finance; development and procurement agreement, fuel supply contract, O&M agreements and a PPA (Vinter 1998).
Development agreement requires an organization to be contracted to construct the infrastructure in a predefined timespan for a settled upon cost. As deferrals are expensive the venture organization requires reimbursements against such risk, consequently would only reach an agreement with an organization with the credit value to bear this risk. The supply arrangement is to guarantee the amount and cost of fuel provided so as to run the station. This may include oil, coal, gas or some other fuel utilized for power. As banks won't take price or volume risk for a venture a purchaser must be accessible. The venture organization will go into a deal with the purchaser normally for 10-15 years. This agreement decides income for the undertaking. The company may still have to sell at a loss due to prevailing economic situations. The bank necessitates a reliable purchaser to balance the danger of them renouncing the agreement in such a circumstance. The O&M agreement is among plant administrator and SPV. The administrator must guarantee the plant operates to a standard where settled upon electricity can be conveyed to the provider.

For a UCG project due to the fact that capital required is lower than compared to hydro or nuclear power and the technology is essentially similar to thermal power generation the construction risk is lower which would be appealing to investors. As UCG combines upstream activities with power generation the supply contract is rendered unnecessary as the coal is already present. As UCG is potentially is a method for producing low cost electricity it will be relatively simple to find a buyer for the power produced. The O&M

contracts will be the most important as drilling wells requires experts and is a significant portion of the cost. Investors will be keen to ensure that these contracts are not only awarded to the best party technically speaking but a party that can bear the risk in case of failure or blunders.

There are sure risks that can't be dispensed with and the venture must utilize resources to minimize those risks. These are legal/regulatory risk where law is passed that may void the agreement or impose unforeseen taxation (Sharma and Tanega 2000). Then political risk, including obstruction by the administration normally caused by changing strategies. Finally, counterparty risks in which a party to the venture lose financial soundness These 'lingering risks' are particularly higher in developing nations (Lamech and Saeed May 2003).

11.3 Underground Coal Gasification Policy

UCG being in initial phases is a type of projects coal rich countries are investing in to determine how it can fit into the countries energy mix. Yerostigaz, an auxiliary of Linc Energy, produces around 1 million cubic meters (35 million cubic feet) of syngas every day in Angren, Uzbekistan. The created syngas is utilized as fuel in the Angren Power Station (ABN, 2009). In South Africa, Eskom (with Ergo Exergy as technology supplier) is working a pilot plant in anticipation of providing commercial amounts of syngas for generation of electricity (Hannah, 2011). African Carbon Energy (Theunissen Project | http://www.africary.com, 2020) has gotten ecological permit for a 50 MW power station close Theunissen in the Free State territory and is prepared to take an interest in the DOE's Independent Power Producer (IPP) gas program where UCG has been reserved as the local supply choice (Gas, 2020).

Dispensing with mining takes out mine security issues (Lazarenko & Kotchetov, 1997). Compared to customary coal mining and handling, the underground coal gasification reduces surface harm and strong waste release, and lessens sulphur dioxide (SO_2) and nitrogen oxide (NO_x) emissions (Burton et al, 2007). For examination, the debris substance of UCG syngas is assessed to be roughly 10 mg/m3 contrasted with smoke from customary coal consuming where debris substance might be up to 70 mg/m3 (Walter, 2007).

India has started implementing new policies to add unconventional coal to the energy mix. According to new policy, the legislature has made a few strides in 2019, including lease of coal squares and move towards liberal policy for pulling in foreign investment in vendor coal mining, including that "the administration may cut out greater squares and lower forthright instalment to make these appealing." The coal ministry has solidified a plan of action and issued a statement about their intentions to invest in CBM and UCG, and in the coming years some substantial advances will be undertaken in terms of projects for CBM, UCG and surface coal gasification technology implementation (The Economic Times, 2019).

With multiple clean energy production practices ranging from the clean cavern practice to sequestration of GHG in cavities and exploiting seams below groundwater makes it an environmentally friendly method of utilizing coal. A report on the Thar coal project concluded that UCG can be summarized as "the clean coal innovation" by catching pre-combustion and post-combustion carbon dioxide. Pre-combustion catches of carbon dioxide, hydrogen sulphide, nitrogen oxides, tar and particulate issues including coal debris can be caught by passing the gas through a gas cleansing plant. Post-combustion CO2 catch can be accomplished by coupling UCG with CCS. The UCG when contrasted with other coal mining methods has least pace of fatal mishaps, most reduced land use and surface effects and most minimal aggravation to the ecology of the site area (Imran et al., 2014).

The Chinchilla UCG project was shut down due to environmental concerns. That has however been attributed to bad practices and distinguished as a sole event by other companies. By using pressure higher than necessary they created pathways in the rocks causing gases to escape into the soil and air. Nonetheless the DEHP found no contamination in the ground water (Cluff Natural Resources PLC, n.d.).

UCG has the potential to revolutionize the energy market in the same manner as shale gas did in America. The use of low quality coal (for surface gasifiers) coupled with the fact that they do not need to be mined makes it a very attractive option for coal rich countries. With the technological breakthroughs in clean UCG energy production using various methods it can be potentially the cleanest form of fossil fuel utilization. While more development in technology and business practices are required, UCG can be an optimal solution for coal rich countries in terms of energy security. It can provide cheap energy without high capital costs of nuclear, hydro and wind power. Additionally, with environmentally friendly implementation of projects its ecological soundness and in terms of public interest could be a close second to renewables while certainly bypassing natural gas energy production.

12. Results and Analysis

The economics of NPPs are less than desirable due to the high capital costs associated with setting up power plants. Historic overruns and disasters have made financial institutions and banks averse to financing such projects as associated risks are too high. That being said their ability to generate cheap base load power in the long run is difficult for other fuel sources to match. The French electricity market is a good example of the advantages of nuclear power but palls in comparison with disasters such as Fukushima and Chernobyl.

Hydropower shares NPPs high capital costs making it difficult to build especially due to highly particular site requirements. Due to fairly cheap O&M however in the long run the cost of electricity becomes not only competitive but over competitive. Investors have traditionally been wary of investing in hydro power due to possible construction overruns similar to NPPs, can be very costly and heavily regulated licensing due to resettling or possible loss of ecosystems. This trend has been changing over time as the world is moving towards renewables. However due to intermittent production (usually mountain ice melting in summer) and limited storage (reservoirs) it is not dependable for base load power but can be used to bear peak loads. While policy wise due to other benefits hydropower generates many positives for society its ability to provide energy security is lower than other fuel sources so it is better to diversify into other fuel sources as well.

Wind power is far more complex than the others to integrate into the energy mix. It has high capital costs and its O&M costs increment with time. This is especially true for offshore farms. Due to intermittent production and lack of storage for excess energy, it causes severe fluctuations in the grids and energy markets to the point Germany has had to pay consumers to use power. Technological improvements and constant innovations are driving these costs lower however and cheaper financing is becoming more widely available for these projects. Policies in many parts of the world are also encouraging it especially since it is a carbon free method of generating electricity.

Solar PV has the lowest capital cost of the renewables in this study. It has much greater flexibility allowing entire cities to turn into solar parks greatly cutting transmission costs and losses. The technology however requires greater development especially in terms of panel efficiency and storage. Cheap financing for such projects is widely available with extensive government support mechanisms. Government policy generally highly favors development of this fuel as it has very high potential. It is less intermittent than other renewable fuel sources.

Natural gas is the most dependable transitional fuel for constant power production with well-developed technology, business practices and economics. The only issue is that it has CO2 emissions and using CCS technology drives up capital costs hence LCOE. There is a fuel price risk associated with this method of production, however this has been around for decades and investors are well versed in dealing with it. Cheap financing is readily available despite risks associated with these projects. Government policy historically has aimed at replacing surface coal gasifiers and furnace oil plants with natural gas fueled plants due to lower emissions. The current policy is to use natural gas power to supplement renewable energy production until the intermittency issues are resolved which will then lead to a phase out of natural gas power.

UCG is still in its early phases in terms of commercial implementation. It is unique as it combines upstream and downstream operations by directly accessing and processing the fuel source and converting it into electricity. It has many advantages in terms of external costs. Capital requirements are not comparatively high as technology is similar to thermal power plants. Due to internalization of upstream activities O&M costs are considerably higher as wells need to be drilled into the coal bed. These can be managed with careful operational practices. The natural CCS potential of redirecting CO2 into the well combined with steam cleaning to remove any harmful substances make it very environmentally friendly. Another advantage is its ability to utilize coal resources which are either unrecoverable through mining or of low quality for surface utilization. Byproducts can be made including diesels and fertilizers increasing its economic viability and decrease stranded asset risk (or loss if realized) as there are alternative application. Once UCG passes the early build phase of its commercial implementation it is very likely investors would and institutions would be willing to provide cheap financing for such projects. Governments are also likely to provide policy support especially those with large lignite and bitumen coal reserves in order to have a transitionary fuel until renewable power technology becomes more effective for base load power generation.

13. Conclusion, Recommendations

The research done in this paper is highly generalized using a variety of examples from a global database. It is clear that each fuel source has its own certain benefits and use hence a comparison cannot be drawn of absolute superiority. Nuclear power for example can be a highly advantageous for providing power for essential installations of a state such as those involved in national security or hospitals. Hydropower can be integrated into the energy mix for peak energy reducing need to add capacity for fossil fuel or additional nuclear plants. The greatest potential to even provide base load power lies in Solar PV due to the constant nature of solar availability. UCG as a new technology has also shown great promise especially in comparison to its fossil fuel counterparts.

It is recommended that further research be carried out using individual countries as a case. Different factors could be included such as transmission frameworks, technical capabilities of local industry, foreign investment policy, availability of fuel resource, energy demand patterns and regulatory frameworks to determine individual efficient transitional energy mixes and a road map to a low carbon or if possible carbon free energy mix.

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Centre for Energy, Petroleum
and Mineral Law and Policy
University of Dundee

Centre for Energy, Petroleum and Mineral Law and Policy
University of Dundee
Nethergate
Dundee
DD1 4HN

e: dundee.ac.uk/cepmlp