Evaluation of cost saving with regard to potential Load Following Ancillary Service cost allocation by complementing Emu Downs Wind Farm with solar PV

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Declaration

I declare that this dissertation is my own account of my research and all references have been acknowledged appropriately as required.

I disclose that I have been employed by APA Group, the owners of Emu Downs Wind Farm for the entirety of the duration I have been undertaking this dissertation.

Based on advice I have received from APA, my understanding is all contents in this dissertation are available for release to public.

Praema Ranga

7th March 2014
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Abstract

Emu Downs Wind Farm (EDWF) has 80MW capacity and supplies power to the SWIS grid in Western Australia, which is governed by the WA’s WEM Rules. Currently, Load Following Ancillary Services (LFAS) costs are allocated to customers as per WEM Rules, on a “postage stamp” basis. IMO is considering imposing a “causer pays” approach to LFAS costs on non-scheduled generators, such as wind farms, as early as 2015.

APA Group, who owns EDWF, proposes to supplement EDWF under existing access arrangements, with a 20MW solar farm to be known as Emu Downs Solar Farm (EDSF). The hypothesis proposed is that the solar farm will smooth variability or ramp rates of the combined wind and solar farm, thereby reducing potential LFAS costs imposed on EDWF.

The research sets out to calculate the LFAS requirements caused by EDWF as well as the combined EDWF and EDSF in order to compare the two. Applying a range of estimated costs, NPV analysis is conducted in order to determine the impact “causer pays” allocation of LFAS costs may have on EDWF as well as combined EDWF and EDSF.

There were limitations to data availability for data in time frames of less than half hour intervals and for solar generation. Hence modelling data from PVSt modelling based on Geraldton BoM meteorological station and power generation data from Greenough Solar Farm, located near the proposed EDSF, were used as a proxy.

Equations outlined in ROAM Consulting (2010) report were adapted and ramp rates of power generation, and ramp rates of forecast data were calculated to determine the LFAS requirements. Analysis of results showed that while the addition of EDSF to EDWF will not smooth the output in absolute terms, the EDSF will reduce LFAS costs proportional to total generation of the combined wind and solar farm.
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1. Introduction

1.1 Brief Problem Statement

Emu Downs Wind Farm (EDWF) in Western Australia has 80 MW capacity and supplies power to the South West Interconnected System (SWIS) grid, which is governed by the Independent Market Operator (IMO) as per Western Australia’s Western Electricity Market (WEM) Rules. Currently, Load Following Ancillary Services (LFAS) costs are allocated to customers as per WEM Rules on a “postage stamp” basis (Cremin 2014a). IMO is considering allocating a “causer pays” approach to LFAS on non-scheduled generators, such as wind farms, as early as 2015.

APA Group, which owns EDWF, proposes to supplement EDWF with a 20 MW solar farm, to be known as Emu Downs Solar Farm (EDSF), under existing access arrangements. The hypothesis for this research is that the proposed solar farm will smooth the variability of the combined wind and solar farm, thereby reducing potential “causer pays” costs imposed on EDWF.

1.2 Research Objectives

The aims of this dissertation are to:

- Develop an understanding of LFAS requirements in a system and how these are met;
- Develop an understanding of WA’s WEM Rules in relation to evaluating and meeting LFAS requirements;
- Determine a methodology for calculating LFAS requirements caused by an intermittent generator;
- Determine the relationship between the volatility of a generator and the LFAS requirement caused by the generator;
• Evaluate potential smoothing in total supply volatility if EDWF is complemented by EDSF;

• Evaluate the cost to EDWF if the “causer pays” approach to load following ancillary costs comes into effect;

• Evaluate the cost to a combined EDWF and EDSF plant if the “causer pays” approach to load following ancillary costs comes into effect and determine if there are any potential savings;

• Understand the process of implementing Rule Changes in a market.
1.3 Emu Down Wind Farms

EDWF in WA is located 30 km east of Cervantes, which is about 200 km north of Perth. The wind farm is west of Brand Highway, off Bibby Road, and is shown on Figure 1.

Figure 1: Google Maps (2014) of Emu Downs Wind Farm (EDWF) as indicated by 'A' with close-up view at the top.

Exact location is 30°30'S 115°20'E (Aussie Renewables 2013; Emu Downs Wind Farm 2013).
Figure 2 shows the location of several wind farms supplying power to the SWIS in Western Australia, including EDWF.

The EDWF cost $180 million to construct and was a joint development between Stanwell Corporation and Griffin Energy. It began production in 2006. In 2011, the EDWF was sold to the APA Group.

The EDWF has 80 MW capacity and consists of forty-eight 1.65 MW Vestas wind turbines with turbine hub height of 68.5 m and blade length of 41 m. The average energy expected from EDWF ranges between 198 to 260 GWh per year (Aussie Renewables 2013; Emu Downs Wind Farm 2013).

The EDWF is classified as a non-scheduled intermittent generator as per WEM Market Rules 2014. Based on current WEM Market Rules 2014, EDWF is not penalised for failing to meet its daily Resource Plan forecast submitted to IMO and System Management (IMO 2013b,
p.19). However imposing “causer pays” LFAS costs on intermittent generators will make it necessary for EDWF to improve its wind generation forecasting accuracy in order to reduce LFAS costs, and to reduce the variability of its output to meet future compliance obligations which may be introduced by IMO. EDWF is not a Short Term Energy Market (STEM) participant. Like all scheduled and non-scheduled facilities alike, EDWF is a participant in the WEM’s Balancing Market.

1.4 LFAS for WA’s WEM

At present, the total cost of providing LFAS service to the SWIS grid is passed on to customers via an allocation to market customers or retailers, through the IMO settlements process as per WEM Rules on a “postage stamp” basis, by which a standard price is allocated to all customers irrespective of their system use. However IMO has been considering the option of penalising the causers of frequency imbalance, including non-scheduled power generators such as wind farms via the allocation of a “causer-pay” approach to LFAS costs in order to send a price signal to intermittent generators. A more detailed discussion of the proposed rule change can be found under section 1.8.

1.4.1 Ancillary Services

Ancillary Services is defined by WEM Market Rules 2014, chapter 11 (IMO 2014a, p.419) as “A service … that is required to maintain Power System Security and Power System Reliability, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality.”

Ancillary services include load following service, spinning reserve service, load rejection reserve service, system restart service and dispatch support service, as defined by WEM Rules 2014, clause 3.9 (IMO 2014a).
1.4.2 Defining LFAS

Load Following Ancillary Service is defined as

“the service of frequently adjusting:

(a) the output of one or more Scheduled Generators; or

(b) the output of one or more Non-Scheduled Generators,

within a Trading Interval so as to match the total system generation to total system load in real time in order to correct any SWIS frequency variations.” (IMO 2014a, clause 3.9.1 p. 138)

2014 WEM Rules, chapter 11 defines the term ‘balancing’ as:

“The process for meeting supply and consumption deviations from contracted bilateral and STEM positions in each Trading Interval.”(IMO 2014a, p.420).

The IMO’s LFAS Requirement Investigation in Oct 2013 concluded that

“the market rules do not explicitly define the boundary between LFAS and balancing (or between LFAS and the other Ancillary Services), or prescribe how LFAS usage should be measured.” (IMO and Western Power 2013, p.37)

Hence the difference between balancing and LFAS is unclear at present. IMO has yet to determine a definition or methodology for defining or calculating LFAS requirements. The methodology selected for calculating LFAS in this research is detailed under section 0.

LFAS can be described as the increase or decrease in power generation required to maintain the balance between power demand and power supply so that the load versus supply imbalance does not cause the system frequency to deviate from its required bandwidth. In some other jurisdictions such as New Zealand, LFAS is also referred to as “frequency
keeping service” (New Zealand Electricity Commission 2010). IMO and WEM do not allocate a specific time interval to define load following service (IMO 2013a) other than the trading interval, which is a period of 30 minutes starting every hour or half hour (IMO 2014a, p.448). In electricity markets in the United States, load following service is defined as the service required to follow load over relatively long periods of around half an hour, requiring slow ramp rates (Hirst and Kirby 1999; Nobile et. al 2000; Kirby 2007). LFAS required to respond to load variations in intervals of seconds or minutes with fast ramp rates, is defined as regulation in the United States (Hirst and Kirby 1999; Nobile et. al 2000). Very fast response LFAS requirements of 10 seconds or less are covered by Automatic Generation Control (AGC) within the system (IMO 2014c) for the SWIS in WA. Ramp rates refer to the rate at which a power generator raise or lower their power output.

1.4.3 Causes of LFAS Requirements

System Management is required to forecast the daily load of the system by 7.30am for each trading day, as per the requirements of WEM Rules 2014, clause 7.2.1 (IMO 2014a) and provide this information to IMO as per the required procedures of WEM Rules (IMO 2014a) clause 7.2.3. The main cause of LFAS requirements arising in a market is the variation of actual load from system load forecast (IMO and Western Power 2013). An analysis by IMO and Western Power revealed that possible reasons behind this variation include load shedding due to network disturbances, unexpected changes to large unit loads, and the impact that rooftop PV systems have on load during variable cloud cover (IMO and Western Power 2013, p.9).

The same study found the second biggest contributor to the need for LFAS comes from dispatch instructions being issued by System Management to market participants at Balancing Merit Order (BMO) ramp rates (IMO and Western Power 2013, p.15). BMO refers to
“the ordered list of Balancing Facilities, and associated quantities, determined by the IMO under clause 7A.3.2.” (IMO 2014a, p.422)

In other words, the BMO refers to balancing facilities which have been ranked for a trading interval from the lowest to highest operating short run marginal costs. At present, dispatch instructions are issued based on the ramp rates listed in the BMO, which are the ramp rate limits from the facility’s balancing submission (IMO and Western Power 2013, p.15).

However BMO ramp rates do not match the actual ramp rate that would achieve the required dispatch or forecast requirement. The variation between the two ramp rates is the second largest cause of LFAS requirements in the WEM (IMO and Western Power 2013, p.18).

The third largest cause of LFAS requirements is the variation of actual output of non-scheduled generators from the forecast (IMO and Western Power 2013, p.18). Wind farms are classified as intermittent generators as discussed in section 1.1 of this dissertation.

According to WEM Rules 2014, clause 2.29.4(a) (IMO 2014a), intermittent generators with a capacity greater than or equal to 5 kW must be registered as non-scheduled generators. This is noteworthy as IMO is proposing a rule change that targets non-scheduled generators such as wind farms, which are only the third largest contributor to LFAS requirements.

The main reason behind the variation of actual output of non-scheduled generators from the forecast was identified as wind fronts passing wind farms, whereby large enough wind speeds can trip wind turbines, causing them to shut down (IMO and Western Power 2013, p.11). It has also been identified that avoidable events such as sudden ramps downs by wind farms for planned maintenance outages contribute significantly to LFAS requirements (IMO and Western Power 2013, p.11).

The fourth contributor to LFAS requirements is identified as the deviation of scheduled generators from dispatch instructions (IMO and Western Power 2013, p.18). WEM Rules
2014, clause 2.29.4(b) and (c), and 2.29.6 (IMO 2014a), define scheduled generators as either non-intermittent generators of above 10 MW capacity, or non-intermittent generators of above 0.2 MW capacity with the ability to respond to dispatch instructions from System Management. The main reasons behind the variation of scheduled generator output from dispatch instructions were identified as delays in the scheduled generators responding to dispatch instructions, delays in issuing dispatch instructions to the scheduled generators, deviation of ramp rate of the scheduled generators from that specified in the dispatch instructions and failure of scheduled generators to meet their required outputs (IMO and Western Power 2013, p.14).

1.4.4 Consequences of failing to meet LFAS requirements

As discussed earlier, failing to provide adequate LFAS to the system in a timely manner will lead to the system frequency breaching its acceptable range. All grid connected equipment is designed to stay within an operational range of voltage, frequency, current and impedance (Western Power 2011). The system frequency increasing or decreasing beyond the design range can result in damage to motors and tripping of generators (Western Power 2011). Generators failing to meet load will lead to further decreases in frequency, while generation exceeding demand will lead to increase of the system frequency (Western Power 2011).

1.4.5 Provision of LFAS services to SWIS

According to WEM Rules 2014, chapter 11 (IMO 2014a p.358), LFAS facilities need to comply with the requirements of WEM Rules 2014, clause 7B.1.2 (IMO 2014a). As per WEM Market Rules, facilities which provide LFAS will need to comply with the requirements of Power System Operating Procedures on Ancillary Services by System Management (2009b). Both scheduled and non-scheduled generators can provide LFAS if they meet the criteria required by the Power System Operating Procedures on Ancillary Services by System Management (2009b, p.5).
For the financial year 2014/15, LFAS requirements are estimated to be 72 MW for raise and 72 MW lower, with a ramp rate of ±14.4 MW/minute (SKM 2013, p.27). The average load following raise between 1\textsuperscript{st} July 2012 to 30 April 2013 was 96 MW while the load following lower for the same period was 90 MW (Western Power 2013, p.2).

The cost of providing ancillary services to the SWIS for the year 1\textsuperscript{st} April 2012 to 31\textsuperscript{st} March 2013 was a total of $57,116,901 (Western Power 2013, p.5). Ancillary Services costs are determined by WEM Rules 2014, clause 3.13.1 (IMO 2014a) and are collected from market participants by IMO on behalf of System Management, based on WEM Rules (Western Power 2013, p.5).

1.5 Electricity market overview

The SWIS grid and WEM are governed by the WEM Rules developed by the Office of Energy of the WA state government. The Independent Market Operator (IMO) operates and develops the WEM. IMO’s roles and functions are covered under the WEM rules (IMO 2014a). IMO’s role includes the administration, maintenance and development of the WEM Market Rules (IMO 2014a, clause 2.1.2).

In 2006, IMO established a Market Advisory Committee (MAC) to advise the IMO on market rules, procedures, the electricity market and SWIS operational matters. MAC members include representatives from generators, IMO, system management, ERA and customers. The role of MAC is outlined under WEM Rules 2014, clause 2.3.1.

In 2008, MAC formed the Renewable Energy Generation Working Group (REGWG) to assess the impact that increased renewable energy generation has on the need for ancillary services and the impact of increased intermittency (IMO 2013). REGWG completed its studies in September 2010 and has been inactive since (IMO 2013).
The power produced by EDWF is wholly purchased by EDWF’s client Synergy, Western Australia’s electricity retailer. As of 1st January 2014, EDWF’s client has merged with the state’s generator, Verve Energy, to form a single entity while retaining ring-fencing of generation and retail business units (Department of Finance, Government of Western Australia 2013).

1.6 SWIS Grid and Operation

The SWIS grid is built, maintained and operated by Western Power, the state owned corporation governed by an independent board reporting to the State’s Minister for Energy (Western Power 2014). Western Power was established under the Electricity Corporation Act in 1994 (IMO 2014a, p.449). The SWIS network covers 261,000 km² of area within WA (Western Power 2014).

System Management is a separate business unit of Western Power, ring fenced from the rest of Western Power (Western Power 2014). Its role is to implement the WEM Rules and to be responsible for the operation and control of generator facilities, transmission and distribution networks, retailer supply management and demand side management. WEM Rules 2014, clause 2.2 (IMO 2014a) describe the functions and roles of System Management, as being responsible for the real time operation and management of the power system. It is System Management’s responsibility to maintain the system frequency within its ideal band, and to manage demand and supply balancing.

Western Power is required to maintain the SWIS system frequency between 49.8 Hz to 50.2 Hz 99% of the time, as per the requirements of the Power System Operating Procedure: Power System Security (System Management 2009b, p.10). The frequency operating band can increase from 48.75 to 51 Hz due to a single contingency event, returning to normal range within 15 minutes, and to an operating band of 47 to 52 Hz in multiple contingency
events, returning to the normal range within 15 minutes (System Management 2009b, p.10).

Frequency variation in the grid is caused by mismatch between the total system generation and total system load, in the order of 1 Hz for every 300-400 MW of mismatch between the load and total generation (Clarke 2014).

1.7 Intermittent generators and impact on LFAS requirements

According to 2014 WEM Rules, Chapter 11 Glossary, p. 430, an intermittent generator is defined as:

“A Non-Scheduled Generator that cannot be scheduled because its output level is dependent on factors beyond the control of its operator (e.g. wind).”

Therefore as per WEM Rules, EDWF is classified as an “intermittent generator”. The European Wind Energy Association recommends using the term ‘variable’ generator rather than ‘intermittent’ generator as wind power does not normally start and stop irregularly, as implied by the term ‘intermittent’ (Lin et. al. 2012). Wind power normally varies in intensity over time, and therefore the term ‘variable’ generator has been recommended (Lin et al. 2012). While this recommendation has been adopted in many North American and European electricity markets, the Western Australian electricity markets continue to use the term ‘intermittent’ generator as seen by use of this term in WEM Rules (IMO 2014a). In this report, wind generation will be referred to as ‘intermittent’ generation in order to maintain consistency with IMO and the WEM Rules, despite this term not being an accurate description of wind power.

The intermittency of wind energy is said to comprise of two aspects: the variability of wind output which cannot be controlled, and the partial unpredictability of the wind power output (Perez-Arriague and Batlle 2012, p.2). Wind turbines are equipped with over-speed protection which trips the wind turbines when the wind speed exceeds a predetermined level in order to
protect the wind turbines from damage. In addition to the variability of wind power generation, the high ramp rates resulting from over-speed protection of wind turbines can contribute to high LFAS requirements in the system (Eurelectric 2010, pp.26-27). An example of this issue was witnessed in Spain in January 2009 when over-speed protection resulted in 6 MW imbalance between forecast and actual wind generation (Eurelectric 2010, pp.26-27).

Wind energy output over larger areas was found to have less variability than wind energy from a single plant (Perez-Arriage and Batlle 2012, p.2). Hence it can be argued that system management should play a bigger role in predicting total wind output for the whole system rather than relying on forecast from individual wind generators. Near term wind predictions are found to be more accurate than day-ahead forecast (Perez-Arriage and Batlle 2012, p.2). Hence there is an argument for replacing the current day-ahead Resource Plan system with a more dynamic forecasting system with frequent submissions throughout the trading day in order to better manage LFAS requirements in the system.

There is often an inference in the literature that a threshold exists within an electrical energy system for a certain level of wind power penetration, beyond which operating costs of the system will increase significantly, and below which costs will remain negligible (DeCarolis and Keith 2005, pp.69-70). Studies conducted by DeCarolis and Keith (2005) concluded that even small-scale non-dispatchable wind farms can incur real costs to a system and the threshold argument oversimplifies facts by exaggerating the costs of large levels of wind penetration while understating the costs of small scale wind (DeCarolis and Keith 2005, p.76). This finding can challenge the often repeated notion that increasing wind penetration increases operating system costs and therefore actions need to be taken to address the increasing reliance on wind power.
However, studies by Kalantari and Galiana (2010) on the use of load curtailments on wind penetration in day-ahead markets to reduce the cost of load following services found that wind curtailments at higher levels of wind penetration help reduce the cost of operation by reducing LFAS costs.

1.8 Pre Rule Change Discussion

According to WEM Rules (IMO 2014a), clause 2.5, any person, member of the public or IMO can make a rule change proposal. IMO’s role is to consider how the proposed rule change will contribute to WEM’s market objectives, and to accept or reject the rule change proposals.

WEM Rules (IMO 2014a) clause 3.15.1 requires IMO to conduct a study of Ancillary Services standards and requirements at least once every five years with assistance from System Management.

In 2010, the Pre Rule Change Discussion Paper PRC_2010_27 was introduced by IMO in order to investigate a “causer pays” approach to allocating LFAS costs. The “causer pays” approach refers to the approach of allocating LFAS costs incurred to the system by the forecasting errors of wind generation. This will penalise wind power generation for its unpredictability.

The REGWG was tasked with further investigation of this proposal. Private sector consultant, ROAM Consulting was engaged by REGWG to conduct the analysis of frequency control service requirements of the SWIS for different levels of wind turbine penetration (ROAM Consulting 2010).

Some the main issues raised during the discussion of the PRC involved the costs of LFAS being unacceptably high and the lack of clarity regarding the provision of LFAS in the WEM
and the quantity of LFAS used and required (IMO 2013). Other issues raised during investigation of the PRC included the lack of a clear boundary between LFAS and balancing, the treatment of non-wind intermittent generators, the treatment of uninstructed fluctuations by scheduled generators, and the lack of robustness in the current method of determining LFAS costs as per WEM Rules (IMO 2012).

Based on the joint investigations into LFAS requirements, IMO and System Management made a number of recommendations to WEM (IMO 2013, p.4). MAC agreed that the Pre Rule Change (PRC) will not be progressed but that IMO would continue in its investigation into the issues that were raised during discussion of the PRC (IMO 2013). The implementation of the “causer pays” approach to LFAS cost allocation, to follow the conclusion of the Ancillary Services Review, is one of the longer term recommendations. The target for completing the Ancillary Services Review has been set for November 2014 (IMO 2013).

Hence, while the “causer pays” approach to LFAS is not currently in place, it is likely to be implemented in the future, and possibly even as soon as 2015. The intended implications of implementing the “causer pays” approach to LFAS cost allocation is to provide an incentive for wind power generators to improve forecasting accuracy and invest in technical upgrades to reduce ramping rates and variability of wind power. The unintended implications may include the unfair penalising of wind technology by failing to effectively and fairly penalise other causers of LFAS requirements in the system and slowing down investment in the renewable energy industry by creating an uncertain environment.

1.9 Proposed EDSF

As power generation during peak hours has a higher wholesale price than during off-peak periods (IMO 2014c), supplementing wind with solar power generation can add value to the
existing EDWF. APA Group, which owns EDWF, proposes to construct a 20MW solar PV power plant, to be known as Emu Downs Solar Farm (EDSF), to complement EDWF. EDSF is proposed to utilise existing EDWF transmission connection assets and the existing EDWF network access agreement.

It is hypothesised that complementing EDWF with EDSF can reduce the power output deviation and therefore reduce LFAS requirements caused by intermittency of non-scheduled power generation. Deviation here refers to the volatility of wind power output in and of itself. Applying a range of assumed LFAS costs, potential savings from installing the proposed EDSF is evaluated in this study, in the event a “causer-pays” approach to LFAS cost allocation comes into effect. Refer to section 0 for more information on the methodology used for this study.

Solar power generation generally matches periods of high demand during the day whereas wind power generally has a lower correlation with peak demand during the night in most systems worldwide (Perez-Arriage and Batlle 2012, pp.2-5). The WEM Rules define peak hours of load demand on the SWIS grid as between 8am to 10pm (IMO 2014a, p.439) and off-peak hours of load demand as between 10pm and 8am (IMO2014a, p.438). Figure 3 shows higher solar output during the WEM peak periods and higher wind output during WEM off-peak periods. At present, wind generation from EDWF increases during off-peak periods, and decreases during peak periods, on average. Solar PV output is more predictable than wind power during days with lower cloud cover, such as in summer (Perez-Arriage and Batlle 2012, p.2).

In 2013, APA Group commissioned modelling of a 20MW solar facility near the location of EDWF (GL Garrad Hassan 2013). The average daily power generation profile showed the solar generation falls within the peak demand period of the SWIS grid from 8am to 10pm.
Figure 3 illustrates the daily average output of EDWF and the modelled daily profile of the solar farm.

![Daily - Average Output Profile](image)

Figure 3: Average daily wind profile of EDWF (2011) and average solar modelling profile (Wind and Solar Generation Data, 2013)

It has been proposed that the solar farm is located at the north-east corner of Emu Downs, where it will cover an area of 50-60 hectares of cleared land (Master Plan 2013). The proposed solar farm will not include solar tracking, and no business case has been made for inclusion of an energy storage component at Emu Downs.
2. Background

2.1 Literature Review

It should be noted that no peer reviewed literature or prior research has been identified in the specific area of allocating a “causer pays” approach to LFAS costs on intermittent or variable generators. This may in part be due to different terminologies used to describe load following ancillary services in different jurisdictions, with different approaches taken in separating and labelling slow, intermediate and fast response load following services.

Nanduri and Das (2009) conducted a survey on the critical areas of research in restructured electrical power markets. It is noteworthy that one of the challenges found to be facing the deregulated electricity market is ‘maintaining system reliability (Nanduri and Das 2008, p.181). The five main areas of focus found in the literature review conducted by Nanduri and Das (2009) were price forecasting, bilateral contracts, auctions and bidding, determination of optimal bidding strategy and market power mitigation (p. 182).

Nanduri and Das (2009) conclude that despite the deregulated electricity market being widely researched for several years, there is a lack of a unified approach for electricity deregulation and a need for more research in this topic (p. 189). Provision of ancillary services does not appear to be a prominent area of research. It was found that much of the literature available in the area of ancillary services provision were from government or utility commissioned studies or investigations rather than from academic research.

2.2 LFAS in other electricity markets

The allocation of LFAS costs in an environment where intermittent generation into traditional generating systems is increasing rapidly, is causing concerns in many jurisdictions around the
world, as market operators grapple with an appropriate way of meeting any additional costs caused by intermittent generators.

In the eastern states of Australia, the National Electricity Market (NEM) is operated by the Australian Energy Market Operator (AEMO). NEM applies a “causer pays” approach to regulating raise and lower services (AEMC 2008). The costs are allocated to market participants for five minute intervals, and costs distributed proportionally between customers and generators (ROAM Consulting 2010, pp.96-7). AEMO also applied a ramp rate limit of 3MW/minute (NEM Rules) to generators. The ramp rate limit would require wind generators to install ramp control to prevent sudden ramp up and ramp down of the wind farm output, and therefore reduce the ability of wind generators to cause sudden and large fluctuations, thereby preventing the requirement for large fast-response LFAS in the system.

Due to the increasing capacity of wind power in the NEM and its impact on power system security, the status of wind farms was changed from “non-scheduled” to “semi-scheduled” generator as of May 2008. While still exempt from all the rule requirements for scheduled generators, wind farms are now subject to central dispatch processes and projected assessment of system adequacy (PASA) procedures (AEMC 2008, p.1). This enables the system operator to curtail wind generation quantities, as and when required, in order to maintain the system frequency within its required operating range while reducing load following requirements and therefore keeping operating costs low. This can however reduce the profitability of wind generators.

In the United States, LFAS costs are traditionally allocated to customers based on aggregated energy consumption, or load (Ela et. al. 2012, pp. 3-4) and not based on causation of variable loads. Ancillary Services costs have also been traditionally allocated to loads rather than generators (Smith et. al 2010).
However the rapid increase of wind penetration in the US energy markets in the past ten years has raised concerns regarding the impact of wind energy’s variability on the reliability of electricity grids (Gardner and Lehr 2012, p.13). This has led to ongoing investigation into market restructuring and alternative options for the provision of more cost-effective ancillary services and reducing LFAS requirements in the system.

Ela et. al (2012) analysed how ancillary markets are implemented in the US and how increasing penetration of variable energy may require changes to the design of ancillary services (p.1). The conclusion was that the initial design of electricity markets did not account for increasing wind penetration (p.7). The authors stated that any changes should be implemented after careful consideration to avoid unintended consequences (p.7). It is also suggested that ancillary services may be provided by variable renewable energy resources (p.7) which traditionally was not the case. It is noted that LFAS charges are currently passed on to customers in the United States based on a consumption basis and not causation basis (p.7). An alternative approach of charging loads, based on causation of variation and charging variable generators, is mentioned as a consideration (p.7) but not discussed in any further detail.

Hirst and Kirby (1999) studied the separation and measurements of regulation and load following ancillary services in the US electricity markets and concluded that load following is based on 30 minute rolling averages while it is recommended that regulation be based on 60-second averages.

In New Zealand, the Electricity Commission recovers frequency keeping procurement costs from customers in proportion to their energy purchase (New Zealand Electricity Commission 2010). The New Zealand Electricity Commission issued a consultation in 2010 on proposed modifications to frequency keeping cost allocation, which intended a “causer pays” approach
targeting intermittent generators (New Zealand Electricity Commission 2010; 2013).

Submissions received in response to the 2010 Consultation Paper preferred to delay the proposed changes until the introduction of the Multiple Frequency Keepers (MKP) Project. The MKP Project is intended to find alternative methods of providing ancillary service by subcontracting them to external providers.

As the MKP Project has progressed along since 2010, the New Zealand Electricity Commission (2013) has issued a project brief in August 2013, to develop a new frequency keeping cost allocation methodology. The project is scheduled to enter its second stage of assessment of issues and options by the end of June 2014 (New Zealand Electricity Commission 2013, p.9).

Based on a 2007 investigation of market rules by the European Wind Energy Association, it was determined that wind energy generation is rarely penalised for its intermittent nature in the European and UK energy markets, with some exceptions (Morthorst et. al. 2007). More recent literature in this area has not revealed any significant developments in this area. However a detailed survey has not been carried out, as it is not within the scope of this research.

In Finland, balancing price is applied to wind producers (Morthorst et. al. 2007, p. 164). In Sweden, wind producers, along with other generators pay spot market price for deviations if the system requires down-regulation (Morthorst et. al. 2007, p. 229). In Ireland, technical conditions have been placed on wind energy plants to help the market operator to better manage the system (Morthorst et. al. 2007, p. 198).

In Germany, the Renewable Energy Sources Act, also known as EEG, set specific tariffs for individual technologies based on their power generation costs, with the objective of providing renewable energy projects with a guaranteed return on investment and promoting the increase
of renewable power in the system (Brown 2013, p.7). EEG also provides a ‘system services’ bonus. ‘System services’ is the terminology used to describe ancillary services. The bonus is provided for wind projects that comply with requirements to provide services such as frequency and voltage control, with the objective of providing an incentive for wind power generators to install technical solutions that can provide system services which will be required as Germany’s wind penetration levels increase (Brown 2013, p.8).
3 Methodology

3.1 Overview of methodology used

The objective of this research is to compare the LFAS requirements incurred by the fluctuations of the 80MW EDWF output, against the LFAS requirements incurred by the proposed 20MW EDSF operating together with EDWF as combined generation.

The hypothesis proposed for this study is that the combination of solar and wind farm would reduce the LFAS requirements caused, and therefore reduce any LFAS penalty, should the “causer pays” approach to LFAS cost allocation come into effect.

The methodology undertaken is outlined below in general terms:

- Calculate half hourly wind power deviation;
- Calculate half hourly solar power deviation;
- Calculate the half hourly power deviation of combined wind and solar generation;
- Calculate resource plan deviation for wind;
- Calculate the deviation of modelled solar data;
- Calculate the deviation of combined wind resource plan and modelled solar data;
- Calculate the half hourly LFAS requirements incurred by the EDWF for a year;
- Calculate the half hourly LFAS requirement incurred by EDSF for a year;
- Calculate the half hourly LFAS requirements incurred by combined EDWF and EDSF generation for a year;
• Compare the difference in LFAS requirements of wind power against the LFAS requirements of EDSF and the LFAS requirements of combined wind and solar power generation both statistically and graphically;

• Calculate the percentage of the absolute LFAS requirements against the total power generated by EDWF, EDSF and combined EDWF and EDSF;

• Compute the correlation between deviation in power generation and LFAS requirements for all three models of generation;

• Compare the differences between the deviation of wind power, the deviation of solar power and the deviation of combined wind and solar power.

• Calculate the Net Present Value (NPV) of EDWF alone and for EDWF combined with EDSF, for a range of assumed “causer pays” LFAS costs.

3.2 Data Quality

The data provided for this dissertation was limited. This was in part due to commercial confidentiality, and also in part due to delays in the EDSF project getting off the ground, which has meant there is no operational data available from the EDSF as was originally anticipated.

Minute by minute instantaneous power generation data in MW is not available for wind or solar. Only half-hourly power generation data is available for both wind and solar. As no actual power generation data is available for EDSF, Greenough solar farm data was used as a proxy, given its similar climatic conditions and geographical proximity to the proposed EDSF. As Greenough solar farm has 10 MW capacity while EDSF is expected to have 20MW capacity, Greenough solar farm’s power generation data was multiplied by two to represent EDSF data.
The wind resource plan data, which represents the data, is also only available in half hourly intervals. Only modelling data is available for solar generation in half hourly intervals. Modelling of the 20 MW solar farm was done using PVsyst, based on Yingli solar panels, by consultants for APA Group, based on the Geraldton Airport Bureau of Meteorology (BoM) weather station (GL Garrad Hassan 2013). There is no load or resource plan data available for the solar generation component of combined generation at Emu Downs and therefore modelling data was used to simulate the solar load forecast data.

EDWF power generation and resource plan data was provided for 2011 only. Greenough Solar data was available for 2013 only, as it has not been in operation for longer than two years. Only one year’s worth of solar modelling data was available.

No cost or pricing data was available for this project. Rough estimates were obtained from APA Group’s representative, for the purpose of ballpark NPV analysis.

3.3 Assumptions

Due to limited data, or unavailability of data, several assumptions had to be made for this study. It was assumed that Greenough solar farm data were a good indicator of the performance of the future EDSF, due to the relatively close proximity of Greenough Solar Farm to the Geraldton BoM weather station, upon which EDSF solar modelling was based. Greenough Solar Farm is located approximately 50 km southeast of Geraldton.

It has been assumed that the Greenough solar farm’s power generation data represent future power generation of the EDSF although Greenough Solar Farm has First Solar cadmium telluride (CdTe) thin film PV panels while the PVsyst modelling of EDSF is based on Yingli crystalline PV modules. This difference is likely to increase the deviation between the actual solar power output and the load, or resource plan, thereby making the calculations more conservative in proving the hypothesis of this research.
It was assumed that the accuracy of modelling data of a 20 MW solar farm provided a good indication of the accuracy of future submission of daily resource plans. However it is unclear what methodology will be used by the operator of EDSF for daily resource plan nominations, and whether this methodology will yield more or less accurate forecasts than the PVSyst modelling data.

Due to lack of data availability, it has been assumed for the purpose of this research that the difference in the time periods for which the power generation data for solar and wind has been obtained will be of no significance.

It was assumed that System Management did not enforce any curtailments or dispatch advisories to Greenough solar farm in 2013. Dispatches or curtailments issued by System Management can contribute to imbalances and add to the LFAS requirement caused by the generator.

It has been assumed in this research that LFAS service tracks the half hourly variation between load and generation. This is similar to the definition of LFAS in North America, where LFAS is half hourly load tracking while the same service in shorter time intervals is referred to as ‘regulation’. Different costs are allocated to generation and LFAS in the US, and regulation is generally more expensive. This definition contradicts IMO’s final report on LFAS, which associates LFAS with faster response balancing in the order of minutes. However, a formal methodology for calculating LFAS has not been issued by IMO as yet. Furthermore due to the lack of minute by minute power generation data from EDWF or Greenough Solar farm, no available minute by minute modelling data on EDSF and the absence of minute by minute resource plan data, this is the best possible assumption.

At the time of writing Resource Plans are required to be submitted by Independent Power Producers (IPP) such as EDWF, by 12.50 pm each day but the Resource Plans are not binding.
(IMO 2013b, p.19). However in these calculations, it is assumed that the Resource Plans are contractually binding and the generator can be penalised for deviation between the day-ahead forecast submitted in the Resource Plan actual generation.

### 3.4 Equations for LFAS

The IMO’s “LFAS Requirement Investigation: Analysis of LFAS causes and usage” (IMO and Western Power 2013) concluded that

“the market rules do not explicitly define the boundary between LFAS and balancing (or between LFAS and the other Ancillary Services), or prescribe how LFAS usage should be measured.” (IMO and Western Power 2013, p.19)

As the purpose of this research is to combine, on the same grid connection, two uncorrelated intermittent resources and no current methodology exists at present, a reasonable measure should be used to compare the costs of wind and solar LFAS, as confirmed by Shane Cremin (personal communication, 7 March 2014).

Hence for the purpose of this research the LFAS equations chosen are a modified version of IMO’s proposed equations featured in the 2010 ROAM Consulting report (pp.12-13). These equations are based on the deviation of forecast and the deviation of the generation. Unpredicted and rapid ramp downs of wind generators have been identified as a major cause of LFAS requirements in the system (IMO and Western Power 2013, p.11). Hence the difference between forecast ramp rates and actual ramp rates is used to determine the LFAS. The equations selected for the purpose of this research are also influenced by the lack of data availability, and the limited nature of data made available during the course of the research. The proposed methodology in the ROAM Consulting report (2010), section 14 has not been used here as it has been discredited by IMO and section 14 is completely out of date at
present, as confirmed by Shane Cremin, who is a member of IMO’s MAC Committee, by email dated 7 March 2014. The ROAM report was an early effort to develop a methodology for allocating “causer pays” LFAS costs, but was based on the out-dated WEM Rules methodology of calculating LFAS, whereby Margin Peak and Margin Off-Peak values were ascribed by the regulator and reimbursed to Verve Energy for providing LFAS services (Cremin, personal communication 7 March 2014). WEM has since moved to a gross or balancing market with net settlements and IMO has abandoned any plans of using ROAM calculations (Cremin, personal communication 7 March 2014).

Hence, the general equation used is as follows (ROAM Consulting 2010, pp.12-13).

\[ S_i = L_i - W_i \]

Where \( L_i \) is the instantaneous load in MW at a given time \( i \), and \( W_i \) is the instantaneous wind power generated in MW at a given time \( i \).

\( S_i \) is the difference between \( L_i \) and \( W_i \), also known as the load net of the wind:

\[ \Delta S_i = \Delta L_i - \Delta W_i \]

Where \( \Delta L_i \) is the load deviation which is also the predicted ramp rate of wind, \( \Delta W_i \) is the wind power deviation or the predicted ramp rate of intermittent power generation and \( \Delta S_i \) defines the load following ancillary service requirement.

Load deviation is calculated as follows:

\[ \Delta L_i = L_i - < L_{i-15 : i+15} > \]

Where \( < L_{i-15 : i+15} > \) is the half hourly rolling average of the load 15 minutes before and 15 minutes after the given time, \( i \).

Wind deviation is calculated as follows:
\[ \Delta W_i = W_i - < W_{i-45 : W_{i-15} } > \]

Where \(< W_{i-45 : W_{i-15} } >\) is the half hourly rolling average of the wind power half hour prior to the given time, \(i\).

The market operates on a day-ahead scheduled basis, and deviations from the Resource plan result in system imbalance. The Resource plan refers to the half hourly wind energy forecast data in MWh provided for the 24 hours starting from 8am each day. Hence 48 points of forecast data will be provided by the generator to IMO each day. Hence, load in this case, is the resource plan or daily forecast provided to System Management by the EDWF operator at the start of the trading interval, which the actual generation needs to match during each trading interval, in order to reduce the requirement for LFAS in the system. This methodology has been verified by Cremin (personal communication, 7 March 2014).

The data available for this research was only half hourly wind generation data and half hourly resource plan forecast data for the year 2011, as fifteen minute data is not available.

Therefore an adaptation of the above load following equations has been used whereby:

\[ S_{gi} = L_{gi} - W_{gi} \]

---------------------------------- Equation (1)

Where \(W_{gi}\) is the wind or solar or wind and solar combined power generated at a given time \(i\) and \(L_{gi}\) is the respective load at a given time \(i\).

\(S_{gi}\) is the difference between \(L_{gi}\) and \(W_{gi}\) in MW.

Load deviation in MW is as follows:

\[ \Delta L_{gi} = L_{gi} - < L_{gi-30 : L_{gi} + 30} > \]

---------------------------------- Equation (2)

Where \(< L_{gi-30 : L_{gi} + 30} >\) is the hourly rolling average of the load, half hour before and half hour after the given time, \(i\).
The actual power generation deviation in MW is as follows:

\[ \Delta W_{gi} = W_{gi} - < W_{gi-60 : W_{gi-30}> } \]  

Equation (3)

Where \( < W_{gi-60 : W_{gi-30}> } \) is the half-hourly average of the power generation half hour prior to the given time, i.

There is no forecast data specifically for the solar generation as there is no access to historical resource plan data for solar generation. Hence, for this research, the PVsyst modelling data for a 20MW solar farm is assumed to be the forecast data or the load. Greenough Solar Farm is located 200km north of Emu Downs, near Geraldton. Greenough Solar Farm is a 10MW solar farm, which began operating in late 2012. The actual solar generation data was then multiplied by two, to reflect the output for a 20MW solar farm, for the purpose of this study. The manipulated Greenough solar output data was then used to represent the actual solar power generation data. The difference in deviations between the solar load data (PVsyst modelling data) and the solar generation data (Greenough output data for 2013, multiplied by two) was used to calculate LFAS requirements created by the proposed EDSF.

The solar PVsyst modelling data was then combined with the wind resource plan data to calculate the total forecast data of a wind and solar combined plant. The Greenough output data for 2013 was multiplied by two and added to the actual EDWF data from 2011 to derive the total generation data of a combined wind and solar plant. The difference between the deviations of the two sets of data were then calculated to obtain the LFAS requirements of a combined wind and solar power plant.

The source of data used for the research is summarised in the table below.

<table>
<thead>
<tr>
<th>Data</th>
<th>Source</th>
</tr>
</thead>
</table>

Table 1: Data sources for analysis
### Wind Load
EDWF Resource Plan for 2011

### Wind Generation
EDWF power generation data for 2011

### Solar Load (20MW)
PVSyst modelling data

### Solar Generation (20MW)
Greenough Solar Farm generation data for 2013 multiplied by two

### Combined Load
Sum of EDWF Resource Plan for 2011 and PVSyst modelling data

### Combined Generation
Sum of EDWF power generation data for 2011 and Greenough Solar Farm generation data for 2013 multiplied by two

All the data available for this study, including EDWF actual generation data, EDWF resource plan data, Greenough Solar Farm output data and PVSyst modelling data are provided in MWh for every half hour. These values have been multiplied by two in order to convert them from energy output over 30 minutes (MWh) to an assumed constant power output supplied over that same time period (MW).

### 3.5 Analysis Methodology

Statistical analyses of the results were conducted in order to be able to better interpret what they mean.

All the relevant results were obtained for each of the half hourly trading intervals in a full year, including power generation data in MW, load data in MW, load and power output deviation data in MW, LFAS results in MW and LFAS as a percentage of power generation. In order to interpret the results, the full year’s results were statistically analysed. The maximum, minimum, 99.5th, 0.05th, 25th, 50th and 75th percentiles were calculated.
Next, the correlations between various sets of data were determined. Essentially the correlation is a determination of the strength of the linear relationship between two sets of data, with -1 indicating very strong negatively linear relationship, +1 indicating a very strong positive linear relationship and 0 indicating no linear relationship between the two sets of data (Levine et. al. 2008, pp.128-130).

The correlations between the deviation of power output and the respective LFAS were computed for wind power, solar power and combined wind and solar power. The correlations between power generation and the respective loads were calculated for wind power, solar power and combined wind and solar power. Finally, the correlation between wind power and the combined wind and solar power was calculated, along with the correlation between solar power and combined wind and solar power. The purpose of correlation analysis between each of the above sets of data is to establish how well they are linearly related, and therefore determine if there is a relationship between the parameters analysed.

Finally, frequency distribution histograms and frequency distribution curves are generated for the absolute values of LFAS of wind power, solar power and combined wind and solar power for 0MW to 55MW. The difference between LFAS up and LFAS down were ignored for the analysis, and only the absolute value of LFAS was considered. The range of 0 to 55MW was selected based on 100% of LFAS values falling within this range for wind, solar and combined wind and solar power generation. Twelve bins of 5MW steps were used for the analysis. The results were plotted graphically as individual histograms as well as together on one graph as frequency distribution curves.

### 3.6 Methodology of NPV Analysis

The purpose of conducting NPV analysis is to assess whether the EDWF with EDSF would be a prudent investment, by reducing proportional liabilities, and to get an idea of how
“causer pays” approach to LFAS could potentially impact the investment decision. Due to the absence of cost data due to commercial confidentiality, the NPV analysis was done on a simplified cost model, based on educated estimates provided.

Several assumptions had to be made to perform the NPV calculations. It was assumed that the EDWF cost of installation or procurement has been completely paid for and the capital costs are treated as sunk costs.

The life cycle of the EDWF is 25 years but it has been in operation for seven years now. The life cycle of the proposed solar farm is also 25 years but for this analysis a total life cycle of 20 years is considered for both EDWF and EDSF to account for the likely remaining life of the plant.

The assumptions made for the NPV Analysis are outlined in Table 2. These assumptions were provided by Shane Cremin, the owner’s representative of EDWF by email (13 January 2014).

<table>
<thead>
<tr>
<th>Table 2: Assumptions made for NPV Analysis</th>
</tr>
</thead>
<tbody>
<tr>
<td>Peak power revenue including LGC* credit</td>
</tr>
<tr>
<td>Off-peak power revenue including LGC* credit</td>
</tr>
<tr>
<td>Annual Operating Costs of EDWF</td>
</tr>
<tr>
<td>Annual Operating Costs of Combined EDWF and EDSF</td>
</tr>
<tr>
<td>Construction and Installation costs of EDSF</td>
</tr>
<tr>
<td>Discount rate</td>
</tr>
<tr>
<td>Inflation rate</td>
</tr>
</tbody>
</table>
The NPV Analysis was conducted for four different scenarios: no LFAS costs, low LFAS costs, average LFAS costs and high LFAS costs. All cost estimates were provided by Shane Cremin, EDWF’s owner’s representative, on email (13 January 2014). The LFAS estimates are outlined in Table 3.

Table 3: Estimates of LFAS Costs

<table>
<thead>
<tr>
<th>Scenario</th>
<th>LFAS Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>No cost</td>
<td>$0/MWh</td>
</tr>
<tr>
<td>Low cost</td>
<td>$5/MWh</td>
</tr>
<tr>
<td>Average cost</td>
<td>$12/MWh</td>
</tr>
<tr>
<td>High cost</td>
<td>$30/MWh</td>
</tr>
</tbody>
</table>

The standard equations for NPV analysis were used here.

Annual Income = Annual Revenue – Annual Operating Costs

Annual Revenue = (Peak power revenue including LGC credit x Peak power produced per year) + (Off-Peak power revenue including LGC credit x Off-Peak power produced per year)

Australia’s annual Consumer Price Index (CPI) rose by 2.7% at the end of 2013 (Australian Bureau of Statistics 2014). Based on this figure, an inflation rate of 3% was selected. Value Advisers Associates (Bishop and Officer 2009) provided an opinion on the market risk premium on equity over the regulatory period of January 2010 to June 2014 by WestNet.
Energy. They advised the range to be between 7% to 12% (Bishop and Officer 2009, p.1). Based on this range, an approximate midpoint of 10% was selected for the discount rate.
4 Results and Analysis

LFAS for EDWF, EDSF and combined wind and solar were calculated based on the methodology described in Section 0. The calculations were completed on a Microsoft (2010) Excel spreadsheet, which is stored electronically on the compact disc attached to this dissertation. As there are 17,520 half hourly trading intervals in one year, the full results are too large to be included in this report in a hard copy. An electronic copy of the data and calculations is provided on accompanying CD.

Analysis of Equations 1, 2 and 3 used to calculate LFAS, as presented in Section 3.4 show that the LFAS is the result of the difference between the deviation of power generation and the deviation of the forecast generation. Hence LFAS is not the result of the level of deviation of power generation, but the result of the forecast accuracy. In other words, if wind power generation was highly variable on a given day but has been forecast accurately, the LFAS will still be low. If power generation is almost constant but forecast inaccurately, the LFAS requirement will rise.

Hence the premise that solar power generation will improve the total LFAS of combined wind and solar power due to its lower power deviation is a flawed hypothesis. Even if solar generation could be predicted with 100% accuracy, the LFAS requirements of the wind component in a combined wind and solar plant will remain unchanged.

Hence the only way that LFAS of a combined wind and solar plant will be lower than the LFAS of a wind farm alone will be if wind power is over-forecast while solar power is under-forecast or vice versa so that the errors from each component eliminate each other to reduce overall LFAS requirement. Due to the unlikelihood of forecast errors cancelling each other out, it can be concluded that LFAS requirements of a combined wind and solar plant will be
higher than the LFAS requirements of a wind farm due to the accumulation of forecast errors from both wind and solar components.

### 4.1 Results Summary and Analysis

The half hourly load data provided for a year, for wind, solar and combined wind and solar are summarised in Table 4 below.

**Table 4: Half Hourly Load Summary for a Year**

<table>
<thead>
<tr>
<th></th>
<th>Wind Load Plan (MW)</th>
<th>Solar Forecast/Load (MW)</th>
<th>Load Plan Wind and Solar (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum</td>
<td>80.000</td>
<td>20.256</td>
<td>100.260</td>
</tr>
<tr>
<td>99.5th Percentile</td>
<td>79.100</td>
<td>20.256</td>
<td>90.102</td>
</tr>
<tr>
<td>75th Percentile</td>
<td>29.420</td>
<td>11.099</td>
<td>30.080</td>
</tr>
<tr>
<td>Average</td>
<td>17.248</td>
<td>5.369</td>
<td>22.617</td>
</tr>
<tr>
<td>Median</td>
<td>8.360</td>
<td>0.000</td>
<td>17.960</td>
</tr>
<tr>
<td>25th Percentile</td>
<td>1.500</td>
<td>0.000</td>
<td>8.280</td>
</tr>
<tr>
<td>0.5th Percentile</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>Minimum</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>18.525</td>
<td>7.234</td>
<td>19.850</td>
</tr>
</tbody>
</table>

The half hourly generation data provided for a year, for wind, solar and combined wind and solar are summarised in Table 5 below. The graphical comparison of wind generation against solar generation can be found in Appendix A, Figures 8 and 9. The graphical comparison between wind generation versus combined wind and solar generation can be found in Appendix A, Figures 9 and 10. The graphical comparison between wind, solar and combined generation can be seen in Appendix A, Figures 12 and 13.

**Table 5: Half Hourly Generation Summary for a Year**

<table>
<thead>
<tr>
<th></th>
<th>Wind Generation (MW)</th>
<th>Solar Generation Greenough 20MW (MW)</th>
<th>Combined wind and solar Generation (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max</td>
<td>77.626</td>
<td>19.600</td>
<td>93.576</td>
</tr>
<tr>
<td>99.5th Percentile</td>
<td>74.836</td>
<td>19.600</td>
<td>88.599</td>
</tr>
</tbody>
</table>
The calculated deviations for wind, solar and combined wind and solar generation for the half hourly intervals in one year are summarised in Table 6 below. The deviations were calculated as per Equation 3 in Section 3.4. The results show that deviation for wind has higher maximum and lower negative minimum than solar deviation. Hence, wind power output is more variable in half hour intervals than solar power. The results also show that combined wind and solar generation has similar deviation characteristics as wind energy generation. Hence adding solar to EDWF will not significantly alter the variable nature of the combined wind and solar power plant. The graphical representation of power generation deviation can be seen in Appendix A Figures 20 and 21. The graphical representation of one month’s and one week’s power generation deviation versus load deviation for solar, wind and combined wind and solar are seen in Appendix A, Figures 26 through to 31 respectively. These graphs represent the forecasting inaccuracies for each power generation.

Table 6: Deviation of Power Generation

<table>
<thead>
<tr>
<th></th>
<th>Wind Generation Deviation MW</th>
<th>Solar Generation Deviation MW</th>
<th>Combined Generation Deviation MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum</td>
<td>50.501</td>
<td>12.748</td>
<td>50.501</td>
</tr>
<tr>
<td>99.5th Percentile</td>
<td>27.431</td>
<td>6.567</td>
<td>27.423</td>
</tr>
<tr>
<td>75th Percentile</td>
<td>2.971</td>
<td>0.000</td>
<td>3.475</td>
</tr>
<tr>
<td>Average</td>
<td>-0.005</td>
<td>0.000</td>
<td>-0.005</td>
</tr>
<tr>
<td>Median</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>25th Percentile</td>
<td>-3.311</td>
<td>0.000</td>
<td>-3.713</td>
</tr>
<tr>
<td>0.5th Percentile</td>
<td>-22.764</td>
<td>-6.949</td>
<td>-22.828</td>
</tr>
<tr>
<td>Minimum</td>
<td>-51.497</td>
<td>-14.818</td>
<td>-51.497</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>7.250</td>
<td>2.212</td>
<td>7.454</td>
</tr>
</tbody>
</table>
LFAS for wind, solar and combined wind and solar generation for the half hourly intervals in one year are summarised in Table 7 below. The LFAS required was calculated as per Equations 1, and 3 in Section 3.4. The results show that LFAS requirements for wind have higher maximum, higher 75th percentile, lower 25th percentile, lower negative minimum and higher standard deviation than solar LFAS requirements. Hence wind has higher LFAS requirements than solar. The results also show that combined wind and solar generation has similar LFAS requirements as wind energy generation. Hence adding solar to EDWF does not reduce the total LFAS requirements of combined wind and solar plant, but marginally increases the total LFAS due to accumulation of forecasting errors. The graphical representation of LFAS can be seen in Appendix A, Figures 22 and 23.

<table>
<thead>
<tr>
<th></th>
<th>Load Following Service Wind MW</th>
<th>Load Following Service Solar MW</th>
<th>Load Following Service Combined MW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum</td>
<td>51.497</td>
<td>15.449</td>
<td>51.497</td>
</tr>
<tr>
<td>99.5th Percentile</td>
<td>23.297</td>
<td>7.605</td>
<td>23.517</td>
</tr>
<tr>
<td>75th Percentile</td>
<td>3.631</td>
<td>0.002</td>
<td>4.015</td>
</tr>
<tr>
<td>Average</td>
<td>0.004</td>
<td>0.000</td>
<td>0.003</td>
</tr>
<tr>
<td>Median</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
</tr>
<tr>
<td>25th Percentile</td>
<td>-3.286</td>
<td>-0.091</td>
<td>-3.698</td>
</tr>
<tr>
<td>0.5th Percentile</td>
<td>-27.352</td>
<td>-7.343</td>
<td>-27.485</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>7.459</td>
<td>2.385</td>
<td>7.714</td>
</tr>
</tbody>
</table>

The respective absolute values of LFAS requirements were calculated as percentage of power generated by wind, solar and combined wind and solar power plants. The results are summarised in Table 8 below. It can be seen that solar power has far less LFAS requirements as a percentage of power generation. Combined wind and solar LFAS also has substantially lower LFAS requirements as a percentage of power generation compared with wind power, as seen by the 99.5th percentile, average and standard deviation values in the table. This
suggests that complementing solar with wind can improve the LFAS requirements per unit capacity of the combined wind and solar generation, even if the total value of LFAS requirement increases marginally with the increase in total capacity. The graphical representation of LFAS as a percentage of power output on a logarithmic scale can be seen in Appendix A, Figures 24 and 25.

Table 8: Absolute values of LFAS as percentage of Power Generation

<table>
<thead>
<tr>
<th></th>
<th>Wind LFAS as percentage Generation %</th>
<th>Solar LFAS as percentage Generation %</th>
<th>Combined LFAS as percentage Generation %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum</td>
<td>436150</td>
<td>9793</td>
<td>436150</td>
</tr>
<tr>
<td>99.5th Percentile</td>
<td>5691</td>
<td>1276</td>
<td>2156</td>
</tr>
<tr>
<td>75th Percentile</td>
<td>42</td>
<td>58</td>
<td>32</td>
</tr>
<tr>
<td>Average</td>
<td>228</td>
<td>71</td>
<td>129</td>
</tr>
<tr>
<td>Median</td>
<td>17</td>
<td>22</td>
<td>14</td>
</tr>
<tr>
<td>25th Percentile</td>
<td>6</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>0.5th Percentile</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Minimum</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>4354</td>
<td>317</td>
<td>3696</td>
</tr>
</tbody>
</table>

4.2 Frequency Distribution of LFAS Requirements

The frequency distribution histogram of absolute values of LFAS requirements for solar can be seen in Figure 4. It can be seen from the figure that 0 to 5MW is the most common range of value of LFAS requirements for solar in a half hour interval for a 20 MW solar farm.

The frequency distribution histogram of LFAS requirements for wind power can be seen in Figure 5. It can be seen from the figure that 0 to 5MW is the most common range of value of LFAS requirements for a 80MW wind farm in a half hour interval, but LFAS requirements in the 5 to 15MW range is more frequent for wind power than for solar. This may be attributed to the larger power generation capacity of the 80MW wind farm than the 20MW solar farm.
The frequency distribution histogram of LFAS requirements for combined wind and solar power can be seen in Figure 6. It can be seen that the frequency distribution of LFAS requirements of combined wind and solar power is similar to that of the LFAS requirements for wind power. The similarity is further illustrated by Figure 7, which compares the frequency distribution of LFAS requirements for solar, wind and combined wind and solar power.

![Frequency Distribution Histogram of Solar LFAS](image)

Figure 4: Frequency Histogram of Solar LFAS
Figure 5: Frequency Histogram of Wind LFAS
Figure 6: Frequency Histogram of Combined Wind and Solar LFAS

Figure 7: Frequency distribution of LFAS
4.3 Correlation Analysis

The correlation between different parameters is summarised in Table 9. It can be seen that the correlations between the respective power generation deviation and LFAS requirements are negative values. The negative relationship is explained by LFAS being calculated by the subtraction of power generation deviation from load deviation, as seen from Equation 1 in Section 3.4.

A correlation of -1 signifies perfect negative correlation. The correlation between wind deviation and wind LFAS requirement is close to -1. This indicates that there is a strong linear relationship between wind deviation and LFAS. Though wind deviation alone does not directly cause high LFAS requirements if it has been forecast accurately, it may lead to large errors in forecasting, which will cause high LFAS requirements. The strong relationship between wind deviation and LFAS adds weight to the theory that a highly variable source of power generation causes higher LFAS requirements.

Table 9: Correlation between various parameters

<table>
<thead>
<tr>
<th>Data Set 1</th>
<th>Data Set 2</th>
<th>Correlation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind Generation Deviation</td>
<td>and Wind LFAS</td>
<td>-0.97</td>
</tr>
<tr>
<td>Solar Generation Deviation</td>
<td>and Solar LFAS</td>
<td>-0.93</td>
</tr>
<tr>
<td>Combined Generation Deviation</td>
<td>and Combined LFAS</td>
<td>-0.96</td>
</tr>
<tr>
<td>Wind Generation</td>
<td>and Wind Load</td>
<td>0.51</td>
</tr>
<tr>
<td>Solar Generation</td>
<td>and Solar Load</td>
<td>0.88</td>
</tr>
<tr>
<td>Combined Generation</td>
<td>and Combined Load</td>
<td>0.53</td>
</tr>
<tr>
<td>Wind LFAS</td>
<td>and Combined LFAS</td>
<td>0.95</td>
</tr>
<tr>
<td>Solar LFAS</td>
<td>and Combined LFAS</td>
<td>0.26</td>
</tr>
</tbody>
</table>

The correlation between solar deviation and solar LFAS is quite strong, but slightly less so than the correlation between wind deviation and wind LFAS. The correlation between combined wind and solar deviation and LFAS requirement is similar to that of wind. The
A graphical representation of one month’s and one week’s power generation deviation versus LFAS for solar, wind and combined wind and solar power can be seen respectively in Appendix A, Figures 32 through to 37.

The correlation between wind generation and load is quite low, which indicates the accuracy of wind forecast is poor. The correlation between solar generation and load is significantly better than for wind, which shows the forecasting of solar power in half hour intervals is more accurate, despite the forecast and actual generation being for different sites. The correlation between power generation and load for combined wind and solar is only very slightly higher than that for wind. This indicates there is no significant improvement in the forecasting of combined wind and solar forecasting. The graphical comparison of wind generation and load can be seen in Appendix A, Figures 14 and 15. The graphical comparison between solar generation and load can be seen in Appendix A Figures 18 and 19. The graphical comparison between combined wind and solar generation against load can be seen in Appendix A Figures 16 and 17.

The correlation between wind LFAS requirements and combined wind and solar LFAS requirements is 0.95 while the correlation between solar LFAS and combined wind and solar LFAS is 0.26. This is consistent with earlier observations that there is a strong similarity or relationship between wind LFAS requirements and combined wind and solar generation requirements, while any linear relationship between solar and combined wind and solar is low. This may be attributed to the fact that while wind contributes to 80% of the combined wind and solar capacity, solar contributes only 20% of the total capacity, and while wind contributes to a large component of the combined deviation and combined LFAS, solar contributes to less than 20% of the total deviation and LFAS requirements.
4.4 NPV Analysis

NPV analysis was conducted on EDWF only, and combined EDWF with 20MW EDSF plant. Sensitivity analysis was conducted for different LFAS cost scenarios. A discount rate of 10% and inflation rate of 3% were assumed for the analysis. The results are summarised in Table 10. The results demonstrate that supplementing EDWF with solar has positive NPV value, and is therefore recommended. Applying the “causer pays” approach to LFAS costs erodes the additional NPV from installation of solar, but only marginally. Should the “causer pays” approach be allocated to intermittent generators, it cannot be concluded that adding EDSF to EDWF will help to improve the total NPV. Refer to section 3.6 for details of the calculations.

Table 10: Results of NPV Analysis for EDWF and EDSF

<table>
<thead>
<tr>
<th></th>
<th>No LFAS Cost</th>
<th>Low LFAS Cost</th>
<th>Average LFAS Cost</th>
<th>High LFAS Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind Generation</td>
<td>$294,503,014</td>
<td>$292,119,363</td>
<td>$288,782,252</td>
<td>$280,201,109</td>
</tr>
<tr>
<td>Combined Solar &amp; Wind Generation</td>
<td>$315,470,965</td>
<td>$312,924,668</td>
<td>$309,359,854</td>
<td>$300,193,188</td>
</tr>
<tr>
<td>Difference between Wind and Combined Generation</td>
<td>$20,967,950</td>
<td>$20,805,305</td>
<td>$20,577,602</td>
<td>$19,992,079</td>
</tr>
</tbody>
</table>
5 Discussion and Recommendations

5.1 Findings and Discussion

Based on literature review and analysis of the results, the following conclusions can be drawn in relation to the objectives of this research, as outlined under Section 1.2.

- WA’s WEM Rules do not have a clear definition of LFAS, or the difference between LFAS and balancing, or a robust methodology for calculating LFAS requirements.

- Equations from the ROAM Consulting report (2010) were adapted to half hourly intervals to calculate LFAS requirements for this research. These equations are based on the deviation of forecast and the deviation of the generation. Unpredicted and rapid ramp downs of wind generators have been identified as the major cause of LFAS requirements in the system (IMO and Western Power 2013, p.11). Therefore, the difference between forecast power output ramp rate and actual power output ramp rate, is used to determine the LFAS.

- Despite not having a direct causation, a strong linear relationship exists between the volatility or deviation of the power output and the LFAS requirements of the generator.

- It was determined that the EDSF does not contribute to smoothing of power generation volatility of the combined EDWF and EDSF in absolute terms, but does so proportionally by adding additional capacity to the total system while contributing very marginally, or almost negligibly to the increase in the total system’s volatility.

- The NPV of EDWF or combined EDWF and EDSF is eroded very marginally by the introduction of the “causer pays” approach to LFAS; in the order of 1% for low LFAS costs of $5/MWh, to 5% for high LFAS costs of $30/MWh.
5.2 Rule change impact on the electricity market

Any rule changes implemented in the energy market need to enhance the market objectives. The market objectives of the WEM are stated in the WEM Rule (IMO 2014a, p.20). The objectives are to achieve better economic efficiency, encourage competition among generators and retailers, avoid discrimination in the market against particular energy options and technologies, minimise long term cost of electricity, and improve energy demand management (IMO 2014a).

Several adverse effects can result from market rule changes, such as bias against a certain technology. This can result if a “causer pays” approach to rule change is applied to only non-scheduled generators by unfairly penalising or introducing bias against a certain technology, thereby contradicting WEM Rules. Another adverse effect would be transactional inefficiencies due to administrative costs for the generators (Synergies 2004).

If rule changes are implemented ineffectively and need to be fine-tuned regularly, it may result in creating an uncertain environment in the market, which could adversely impact investor decisions (Synergies 2004). Potential private investors seek stable market rules and long term contractual arrangements and are deterred by repeated market redesign, regulatory interventions, limits imposed on energy prices and market imperfections (Joskow 2008, p.28).

Rule changes can also result in increased costs of monitoring the system, or increase the cost of electricity generation in the long run (Synergies, 2004). These factors describe adverse impacts which would be contrary to WEM’s market objectives.

While many countries worldwide have benefitted from electricity market reforms through improved performance, creating a highly effective competitive wholesale and retail electricity market poses both technical and political challenges (Joskow 2008, p.37).
5.3 Technical methods to improving frequency keeping

The variability of solar power is less than that of wind in half hourly intervals and forecasts of solar energy in half hourly intervals is currently more accurate than forecasting wind power as seen from Table 9. Hence supplementing a wind farm with a solar farm will help increase the total generation of the plant without significantly increasing the LFAS requirement created by a combined wind and solar farm. Yet it should also be noted that the addition of solar PV does not actually reduce LFAS costs as the underlying variability of wind output remains.

Other methods of improving the variability of wind power generation include ramp control, energy storage with a suitable control system and improved methodology for forecasting wind generation, which remains an area of rapid research and development at present.

It has been demonstrated on an isolated grid in a Portuguese island that using a flywheel in combination with a power electronics grid interface can help stabilise weak grids with high penetration of variable renewable energy (Hamsic 2006, p.6). Demonstration in Hokkaido, Japan with a 34MW or 250kWh NaS energy storage system with a 51MW wind farm successfully demonstrated improved energy utilisation by using energy storage and time shifting (Lee et. al. 2012). It has been demonstrated, using Matlab simulation, that Double Fed Induction Generation (DFIG) using the same stator side converter can improve power output and enhance power quality and reliability (Aktarujjaman et. al. 2006). Based on modelling a Na-NiCl₂ battery system on Matlab-Simulink, Grillo et. al. (2011) proved that a perfectly smoothed wind output using joint battery storage and an appropriate control strategy was possible but it compromised the battery lifetime by placing too much stress on it due to constant charging and discharging (p.461). Further development in battery technology will be required to overcome such hurdles.
As unpredicted sudden ramp ups and ramp downs of wind farms are a major contributor to LFAS requirements in a system (IMO and Western Power 2013 p.11), various techniques for limiting ramp rates are under research, such as optimising battery operation with wind forecasting based on a recursive Gaussian process (Lee D. et. al. 2012), using the variance gamma process with batteries (Lee and Baldick 2012), using turbine inertia and distributed energy storage (Hovgaard et. al 2013) and Model Predictive Control (MPC) controller based energy storage with wind power smoothing (Khalid 2011). While promising results are demonstrated in this area of research, the development of wind ramp rate control in conjunction with battery storage remains an area of rapid development at present. Siemens, which provides a market ready “NetConverter” system which can control output and required ramp of wind power, promise more development to come in the next few years (Nelson 2011).

Ecoult Energy has successfully installed a MW-scale wind power storage system to demonstrate the ability to limit ramp rates at Hampton Wind Farm in NSW (Ecoult Energy Storage Solutions 2014). Hansen et. al (2014) discuss using optimised wind turbine control systems to reduce wind grid connection costs to provide enhanced ancillary services such as frequency control, power control and dynamic phase control.

While there are many reasons for implementing energy storage, the cost of installing energy storage still remains quite high, though prices are expected to decrease quite rapidly from $1600/kW in the year 2000 to$800/kW in 2013 to as low as $400/kW expected in 2020 (Marchment Hill Consulting 2012).

While a “causer pays” approach to LFAS cost allocation is intended to provide incentives for wind farms to install effective ramp rate control and improve wind forecasting accuracy, the
timing of implementing such a cost may need to be better aligned with market readiness of new and cost effective technologies in this area.

5.4 Alternative market solutions to tackling LFAS costs

Alternative market solutions to meet increasing LFAS requirements of electricity grids include the introduction of bilateral markets for ancillary services (Nobile et. al. 2000), introducing ramp control requirements, and imposing dispatchability requirements on intermittent generators. Alternative methods of procuring LFAS by season and time of day, rather than en-bloc annually to maintain a constant level of service throughout the year, can also reduce LFAS costs (Smith et. al 2010).

As the aggregated wind energy output over a larger area has less variability than the wind output from a single wind farm (Perez-Arriaga and Batlle 2012, p.2), the system operator should bear more responsibility for predicting the aggregated wind resource plan for the whole system through central wind forecasting and using new and more accurate forecasting services, rather than relying on individual resource plan submissions from each wind farm (Smith et al. 2010).

Hirst (2000) investigated the possibility that participation in competitive markets for ancillary services may increase profits for generators, and concludes that generator profitability can increase by 10-50% by participating in the provision of ancillary services. Refer to section 2.3 for information on how ancillary services are provided in WA’s WEM Market. However, due to the dominance of the incumbent generator, Verve, in the SWIS grid, developing a competitive market for the procurement of LFAS will be challenging (SKM 2009, p. 15).

As near term wind predictions are more accurate than day ahead forecasts (Perez-Arriaga and Batlle 2012, p.2), IMO should transition into more frequent submissions for resource plans from variable power generators and away from the current system of day ahead submissions.
As seen in Spain and Denmark, both of which have a very high reliance on variable wind power generation, wind generators are subject to the same level of balancing and scheduling obligations as conventional power systems (Eurelectric 2010, p.29). This is thought to provide wind generators with the incentive required to mature as a technology and truly integrate in order to compete on an equal footing with other generators (Eurelectric 2010, p.29). However in the absence of strong renewable energy targets, this approach may have the opposite effect of eliminating renewable energy generators from the market by imposing additional costs which would make investment in renewables uneconomic, and thereby set back the development of a less carbon intensive and competitive electricity market.

While intermittent generators should be provided with incentives to minimise LFAS requirements imposed on the system, there will always be inherent LFAS costs within these technologies. Given that most renewable energy technologies are often directly and indirectly subsidised, and are often implemented through the social mandate of tax payers and electricity users, LFAS costs, like other indirect subsidies can be borne by electricity users. Hence the “causer pays” approach can be abandoned in favour of the shared funding for social and environmental good.

5.5 Further research

Further research needs to be carried out in examining shorter term, minute by minute or second by second LFAS requirements of wind and solar farms. Further development is also required to formulate more robust equations, to calculate LFAS requirements caused by individual facilities and to determine LFAS cost allocation.

Research also needs to be undertaken on commercially available and economically feasible energy storage solutions with smart control systems available in the market to be able to introduce ramp control without shedding power during ramp up.
6 Conclusions

Provision of LFAS and its costs allocation in the WEM market are an area still under development by IMO. The differentiation between balancing and LFAS remains unclear and no clear methodology has been proposed for determining either.

Based on analysis of half hourly data obtained from historical operating figures at EDWF, Greenough Solar Farm and from modelling figures on the proposed solar farm, it can be concluded that though EDSF would not contribute to smoothing of power generation volatility of the combined EDWF and EDSF, and that EDSF would add additional capacity to the total system, thereby increasing revenues, while contributing very marginally to the increase in the total system’s volatility.

Despite not having a direct causation, it was found that a strong linear relationship exists between volatility of the power output of a variable generator and the LFAS requirements caused by the generator.

NPV analysis, based on educated estimates, found that the NPV value of EDWF and the combined EDWF and EDSF is eroded very marginally by the introduction of a “causer pays” approach to LFAS.

It is recommended that further study is conducted on analysing the impact of minute by minute or second by second LFAS requirements of EDWF and the proposed EDSF.

Options for improving LFAS requirements caused by variable generators such as wind farms include improved forecasting tools and ramp rate control in conjunction with energy storage and an appropriate control system. These areas are under rapid research and development at present.
The “causer pays” approach to LFAS cost allocation has not yet been implemented by the IMO, but this area was investigated in 2010 and has been recommended for introduction, pending further analysis, and may come into effect as early as 2015. Adverse impacts may result from imposing the “causer pays” approach of LFAS cost allocation on selected technologies, which would be in conflict with the market objectives. Several alternative market solutions exist for reducing LFAS costs to the system at present and many more technical solutions for ramp rate control, output smoothing and more accurate wind power predictions are under development. Timing of an introduction of the “causer pays” approach to LFAS cost allocation can be aligned with the market readiness of such technologies in Australia.
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SKM 2009 *Ancillary Service Standards and Requirements Study*


Appendix A: Graphical Output of Results

Figure 9: One month solar vs wind output

Figure 8: One week solar vs wind output
Figure 11: One month wind vs combined output

Figure 10: One week wind vs combined output
Figure 12: One month wind vs solar vs combined output

Figure 13: One week wind vs solar vs combined output
Figure 15: One month wind generation vs load

Figure 14: One week wind generation vs load
Figure 16: One month combined generation vs load

Figure 17: One Week combined generation vs. load
Figure 18: One month solar generation vs load

Figure 19: One week solar generation vs. load
Figure 20: One month’s power deviation

One Month Wind versus Solar versus Combined Wind and Solar Deviation (MW)

Figure 21: One week’s power deviation

One Week Wind versus Solar versus Combined Wind and Solar Deviation (MW)
Figure 22: One month LFAS requirements

Figure 23: One week LFAS requirements
Figure 24: One month LFAS as a percentage of output

Figure 25: One week LFAS as a percentage of output
Figure 26: One month solar output deviation vs load deviation

Figure 27: One week solar output deviation vs load deviation
Figure 28: One month wind output deviation vs load deviation

Figure 29: One week wind output deviation vs load deviation
Figure 30: One month combined output deviation vs load deviation

Figure 31: One week wind output deviation vs load deviation
Figure 32: One month solar generation deviation vs LFAS

Figure 33: One week solar generation deviation vs LFAS
Figure 34: One week wind generation deviation vs LFAS

Figure 35: One month wind generation deviation vs LFAS
Figure 36: One week combined generation deviation vs LFAS

Figure 37: One month combined generation deviation vs LFAS