Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
	Verve Energy	
page 3	"this indicates that wind penetration of around 500 MW is likely to be achievable without system-wide effects". We would argue that deleterious effects are seen much earlier. In fact they are being seen now.	This comment is simply intended as the application of a rule of thumb that has applied in other networks to the SWIS. The wording has been changed in the report to reflect this.
Table 7.1 for Scenario 1	and tables for other scenarios appear to have Collgar commencing operation later than the 2009 Reserve Capacity Auction results indicate. This could be because Collgar was included in Work Package 1 scenarios later than when it would be commissioned. The load following requirement should thus be higher than suggested in the tables.	The scenarios developed in Work Package 1 were used as the basis for the modelling in Work Package 3. In Work Package 1 Collgar Wind Farm enters in 2012-13 and 2013-14, depending upon the Scenario. This is later than the 2009 Reserve Capacity Auction results indicate, meaning that the load following requirement calculated in this report increases one or two years later than if Collgar were to enter in 2011-12. However, the magnitude of the increase upon entry of Collgar and the aggregate load following requirement increase over the course of the study are not affected by the timing of the entry of Collgar Wind Farm.
Table 8.1	It should be noted that the decommitment merit order is not necessarily the reverse of the dispatch merit order. Maybe a separate table should be established documenting the expected decommitment merit order.	ROAM has differentiated between the decommitment order and dispatch merit order in this modelling. The complete order, including decommitment (order of dispatch to minimum load) and dispatch (order of dispatch to maximum load) is listed in the table in Appendix C.1.
Footnote #16	it is suggested that Collgar would increase the load following requirement by 150 MW as reported by MMA. This is not accurate – the MMA report was saying that the load following requirement would increase from 60 MW to 150 MW	This wording has been adjusted in the report to more accurately reflect the assumptions used in the cost calibration study.
ROAM Consulting dispatch model	Cogen plant running at minimum loads - are the minimum loads the same as the steam requirement loads?	Minimum and maximum loads assumed for each station (including cogen plant) are listed in Table A.1 (Appendix A). Minimum loads are intended to be the steam requirement loads.
ROAM Consulting dispatch model	Does this dispatch model consider fuel supply balances – gas contract take-or-pay, maximum contract quantities, pipeline limits and coal contract limits?	This dispatch model assumes as delivered gas prices for each station for the calculation of SRMC values, but does not take into account pipeline limits or maximum contract quantities, beyond assumptions around the original plant mix build decisions. Gas prices used for each plant differed depending upon the proponent (Verve, new IPP or existing IPP) based upon assumptions around contracts. Gas prices used for the dispatch modelling exercise are listed in section 14.9, with the other dispatch model input assumptions.
ROAM Consulting dispatch model	The start up and shutdown cost for thermal plant in Table 8.2 could be flawed. We feel that the shut-down/start-up cost discount of $44/MWh for thermal plant is flawed (Section 8.2). It appears to be estimated as if the thermal plant would be running at full load. The costs need to be spread over a much smaller volume probably the expected STEM/Balancing volume that results in a shut-down or start-up being incurred or avoided. This is likely to be somewhere between 0 MW and the facilities' minimum load. The more accurate formula should be: Start up cost each time/(5 hours run if not shutdown x loading). This challenges a key assumption of the report, namely that thermal plant will be shut-down in preference to curtailing wind. Further work may be required to understand the implications of this assumption not holding true.	This calculation has been updated to reflect operation at minimum loads overnight. However, ROAM does not believe that this challenges a key assumption of the report, since this still produces minimum bids for coal-fired generation in the most extreme case that are comparable to the minimum bid of wind generation. Start-up/shut down costs are difficult to quantify, and little accurate data is available on a station by station basis. Being aware of the lack of accurate information, the analysis included in this section is intended only as an indication that wind farms have substantial opportunity costs (from lost RECs revenue), which are likely to be or fhe order of, or larger than start-up/shut-down costs of coal-fired generators on a per MWh basis.
Minor issues	The dates in section 10.1.1 are probably not 2010	Dates (years) were originally included in the figures in this section, and have now been included in the main text also.
Minor issues	The table reference in the line above Table 11.2 should be Table 11.2 rather than Table 11.4	This has been corrected.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
Minor issues	Table A2 seems to have some discrepancies (looks like the maximum capacity numbers have got out of kilter somewhere in the table - shifted up one maybe).	This has been corrected.
Page 84	The doubling of Margin_Peak in the ERA recent determination from 15% to 30% does not mean doubling of availability cost. MCAP was projected to be lower in the review period of 2010/11 to 2012/13.	The text in the report has been updated to reflect this more accurately.
	The report recommends that wind generators bear only the additional load following requirement on top of what load would have to bear if there were no wind generators on the system. We are not sure that this is appropriate from an economic efficiency consideration. Could this be a distortion in the price signal for wind generators?	As outlined in section 14.10, this is recommended on the basis that managing the variability of intermittent loads is inherent in operating the system. In the absence of intermittent generation, intermittent loads would be required to pay for their full frequency control requirements, and would then receive a windfall gain if intermittent generation was added to the system. It could then be considered "fairer" if the charge for load following service reflected the past history of connections. This is problematic, however, since it subjects those who connect earlier to an ongoing higher penalty. Paying the marginal cost of load following (in excess of the load following required by intermittent loads) allows intermittent generators to pay only for the load following services they require in excess of what is already required by loads (inherently required by the system). This is considered to be accurately representative of the cost burden that intermittent generators place on the system, and an appropriate price signal for wind generators. Additional text further explaining this reasoning has been included in the report.
Section 12	The cycling of all non-cogeneration base load plants (eg Collie, Muja) is impractical and will impact significantly on system security. The impact of wind penetration on overnight dispatch will therefore become a significant issue well ahead of the timelines indicated in Figures 12.1-12.4. Including minimum base load generation in these figures would assist participants' understanding of this issue. Also, with increased cycling of thermal plant, delayed unit return to service is inevitable. This will lead to increased use of fast start machines for energy requirements and the potential that insufficient capacity is available to meet load following requirements.	These figures do not indicate that all coal-fired generation will need to be cycled. They rather indicate the capacity of wind installed with other "must run" plant compared with minimum loads to provide an indication of their relative magnitudes. Coal-fired plant minimum loads are not considered to be "must-run" for this analysis. Importantly, the load will only be this low on one trading interval of one evening of the year, and it is exceedingly unlikely that all wind generators will be operating at 100% capacity at this point in time. This section is intended simply to indicate that discussions around dispatch merit order priorities of wind and minimum loads of coal-fired generation are important and timely. Comments around system security and delayed unit return to service have been added to this section.
Section 14.7 & 14.8- Costs	whilst the accuracy of forecast cost increases are questionable (ROAM admits there is significant uncertainty in the input parameters), our feeling is the costs are of the right order of magnitude. Load following plant tends to be provided by higher cost OCGTs whereas lower cost thermal plant can contribute to spinning reserve. Thus as the load following component of the ancillary service requirement rises, OCGT cost becomes more significant	Noted.
Tables 14.8-14.11 -	Figures quoted under the column heading Availability Cost of Load Following ($ pa) appear to actually be Total Availability Cost, which includes spinning reserve.	This has been corrected.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
We generally agree with the conclusions except:	Intermittent Generators should pay the marginal cost of load following" - as discussed above, it is not clear that this is not economically inefficient. Further consideration is needed in this area. "Dispatch Priorities at time of minimum load" - as mentioned above, this will be an issue much earlier than 2020/21, and indeed is already an issue for Verve Energy which will be significantly exacerbated after Collgar wind farm enters service.	The 2020-21 date simply indicates the point at which installed wind plus "must run" capacity exceeds minimum load. It is acknowledged that dispatch order priorities must be addressed as a priority (further text has been added to the report to reflect this).
We agree with the recommendations except :	"The Methodology in the Rules for the determination of the costs of load following and spinning reserve should be updated as a priority" - we agree but have concerns that the proposed equations in section 14.3 still appear to allocate 50% of the load following requirement to generators. Load following contributes to covering generators spinning reserve requirement, so there is an argument they should contribute to its cost, (hence its inclusion from day one of the market). However an arbitrary 50% allocation is inappropriate, and further consideration is required.	This has been addressed in revised equations included in Chapter 14 of the report.
We agree with the recommendations except :	As above, we are not yet convinced that wind farms should only contribute to the marginal cost of load following above that required for load variability.	Response above.
We agree with the recommendations except :	It is unclear what is the lack of transparency in dispatch merit order priorities. Is it referring to a lack of transparency for IPPs when they are moved off their Resource Plans by System Management?	This wording has been changed to reflect a transparent cost-based dispatch.
We agree with the recommendations except :	Curtailment of Intermittent Generators - the Market Rules require this.	This point is intended to confirm that this is a necessary clause in the Market Rules. The wording has been updated to reflect this.
We agree with the recommendations except :	Recommendations on cost allocations and overnight dispatch need to be given a high priority particularly with the imminent arrival of Collgar wind farm	Noted.
	Western Power	
P ii Timeframe dictates whether load or wind variability dominates	Is ROAM able to comment on the accuracy of predicting load changes compared to the accuracy of predicting variations in wind output?	The scale of the difference over different timeframes far exceeds the uncertainty in predicted load changes compared with predicted variations in wind output. Whilst accurate prediction of a minute to minute load or wind trace is very challenging, this is not necessary for this exercise. For this study the statistics of historical traces projected over time have been used, and this is more robust.
P2 The frequency must also……………………………..or a sudden transmission fault.	A sudden transmission fault will also cause a reduction in the load level, due to the voltage depression, even if no substations are disconnected as a result of the fault	Text to this effect has been added to this section.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
P5 System frequency modelling (fast response)	In the modelling were all the changes in output assumed to occur over a 1 minute time period? Does fast response dynamics consider changes over less than 1 minute?	One minute resolution historical wind and load data was the smallest resolution available. The 99th percentile one minute shift was determined from this data and used as an input to the much finer resolution frequency model, as a constant ramp over one minute. This allowed analysis of system frequency dynamics on timeframes much shorter than one minute, but does assume that there are not significant shifts in wind or load output within one minute (and hence not reflected in the one minute historical data). The one minute wind and load data appears to exhibit constant ramping properties (up and down) over the one minute timeframe, suggesting that high frequency dynamics over periods less than one minute are unlikely. However, if higher resolution data becomes available, this should be analysed to confirm the validity of this approach. Text to this effect has been added to the report.
P11 5.1) b.	Is this measure still appropriate with increased wind penetration? Are changes that occur in less than 1 minute likely to be an issue?	This study suggests that the existing load following definition is sufficient (as explained in the executive summary, and conclusions). This analysis suggests that changes that occur in less than one minute are unlikely to be an issue, although if sub-one minute resolution load and wind data becomes available this should be analysed to confirm the validity of this conclusion.
P17 5.5) Fast response service Discard largest 1% (99^{th} percenbtile).	Why is the largest 1% discarded? Is this a data validity issue?	As explained in the footnote on this page, the 99th percentile has been used here since the frequency standard in the Rules states that frequency must be maintained within the required limits for 99% of the time.
P25 6.2.1) Wind farm correlations	Has any correlation been considered for the wind resource at Merredin? The largest wind farm in the state will be installed in the Merredin area.	One minute resolution data was not available at or near to Merredin (the BOM station at this location only records 30min wind data). Therefore analysis of correlation at this site was not possible at this time.
P46 Where $P_{Gen}(t)$………, and H_{Gen} is the generator inertia in MWs.	In this case H_{Gen} is the inertia of the generator, turbine and all other connected rotating plant and not just the generator.	The text has been updated to reflect this.
P49	The governor droop is normally 4% for most units. Also there are some times when the governors are set on isochronous control to manage frequency.	Text has been added to reflect this.
P87 Incentives for provision of inertia	Has a market approach been considered elsewhere for the provision of inertia? This may also be an issue for OCGTs that are providing frequency keeping services. The increased use of aero derivatives to replace industrial gas turbines and steam units combined with the increased penetration of wind will have a significant impact on system inertia.	ROAM's modelling suggests that contrary to intuition, system inertia does become not a limiting factor in the SWIS at these levels of wind penetration, so long as plant providing load following service has fully tuned governors. Refer to section 11.3 of the report for details. Inertia has become a significant issue in some other markets. Notably, inertia is a significant limiting factor in the Tasmanian grid, and it may eventually become appropriate to consider a market approach or other incentives to encourage provision of inertia in that market (possibly as a part of the NEM ancillary service market).
P89 Provision of load following service during curtailment	Curtailment of the wind output could be as a result of network restrictions in which case the wind farm could not provide a load following service. They will however be able to better regulate their output so that it is less likely to vary.	Text reflecting this has been added to the report.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
P91 Wind exhibits correlation within three distinct zones in the SWIS	Has consideration been given to the Merredin area?	As above.
P91 The timeframe dictates whether load or wind variability dominates	I would expect that both variability and predictability need to be considered. If the output is predictable then less of an issue.	As explained in Section 5.1, zero predictability of wind output has been assumed for this analysis. With increasing accuracy of wind forecasting technologies there could be justification to reduce the load following requirement (by changing the methodology in the rules for determining the load following requirement).
	LGP	
General	Noting the comments on the inaccuracy and inappropriateness of the existing ancillary services payments, I perceive the focus should be on the "First Principles" dispatch modeling.	ROAM believes that both approaches are valuable and provide important insight. Analysis using the methodology in the existing Rules has contributed to finding a variety of flaws and recommended improvements to the Rules which would not have been discovered through a first principles dispatch methodology alone.
General	The First Principles dispatch modeling should not tie itself to the Availability Payment concept, which seems to me to share the impairment described for the current method of reimbursement. I'd prefer an approach based on capacity payment plus energy payment according to merit stack.	ROAM has followed the "compensation" based methodology used by the ERA for determining availability payments. Analysis of further deviation from this methodology (such as the use of energy payments) would be possible; if this is desirable it should be included directly under the scope of future work.
Table 14.3	the capacity cost seems to be $138,000 for al future years, despite a reasonable expectation of a blow-out in from 2012-13	Data to quantify a possible cost "blow-out" was not available, so the average of the past several years was felt to be the best proxy available for future capacity costs.
Table 14.8	scenario 1, 3rd row seems to be wrong	This has been corrected.
S14.8	Suggest reconcile the gas prices with the recent Gas Pricing paper	In the absence of detailed data on market participant gas contracts, the gas prices listed in this section were felt to be an appropriate representation of gas prices faced by various market participants as a basis for dispatch modelling.
Figure 14.4	Is the stated gas price increase a forecast or a fact? If a fact, this will have important consequences for MCAP?	The gas price increase featured in this diagram is simply a graphical representation of the input assumption used for the modelling, to demonstrate the impact that it has on availability costs of load following. The increase in gas price does increase the MCAP, which was incorporated into the calculation of the availability cost. Text explaining this further has been added into the report.
Page 93	Would welcome justification of the assertion that a carbon price would decrease Verve's costs	This is an outcome of the modelling exercise, showing that the "compensation" mechanism used for calculating "availability costs" of load following can have counter-intuitive outcomes. It does not mean to suggest that actual costs to Verve will decrease, but rather that a higher proportion of the cost of load following could be recovered through the market with the application of a carbon price. The carbon price acts to increase the costs of all generators in the system, increasing the system marginal price from $24 /MWh in 2009-10 to $85 /MWh in 2029-30. If Verve's generation volumes remain similar (competitiveness is maintained despite the increased carbon price) this then decreases the "cost" of load following to Verve, as calculated via the existing methodology. This is because the existing calculation of "cost" is actually based upon a compensation mechanism (refer to equation above for calculating availability cost). Verve is compensated for their increase in costs when providing the Load Following service, offset by the amount of revenue that they can recover from the market from sales of energy. Since load following plant is generally less emissions intensive than other plant in the system, MCAP increases more rapidly than do Verve's Load Following costs.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
		This could mean that, if load following availability costs are calculated via the existing methodology, Verve could receive less compensation for load following services with the entry of a carbon price (because they will be receiving a higher proportion of their costs as revenue from the market). Text explaining this further has been added to the report.
Recommendations 1, 4, 5 and 6	These al seem to be pretty much the same thing.	These have been consolidated in the report.
System Management		
General	System Mangement agrees with the major findings in the report. In particular the tradeoff between curtailment of windfarms and daily cycling of coal-fired thermal generation has been identified and should be emphasised in the conclusions of the report. System Management believes that market design changes should be sought which provide a technically feasible least cost outcome to resolve this tradeoff question.	This was not a significant focus of the scope of this work, but has been listed as a major finding in the conclusions and executive summary, with a recommendation of action as a priority. Text suggesting market design changes has been added to the report.
	The report indicates that an increasing demand for load following will be driven primarily by increasing windfarm penetration and that intermittent generation should pay a proportion of the cost of the provision of the load following service. System Management is also aware that technologies which can help meet the load following and energy balancing demand are available to SWIS but are not currently commercial. Market design changes which encourage these technologies should be considered as part of the market cost regime.	ROAM agrees that this would be a good strategy, and has added text to the report to list it explicitly.
Recommendation - Consider reviewing the definition of load following service	System Management agrees that the technical rules do not breakdown explicitly the definitions of load following - this is implicitly done in the specification of load following. System Management examines the spectrum of 1 minute, 5 minute and 15 minute load/wind movements and converts this to ramp rate requirements of different quantities. The time frames are about right. Fast response (governor/inertia response times), below 30 seconds is really not in the AGC regime, it should be noted that most non-service providing units (non verve plant) have control systems that counteract the governor controls in this time frame. Regulation response is also about right as this is an ideal re balancing (new economic dispatch allocation) timeframe as per NEM. Slow Response is also about right. System Management uses 30 minutes as this is the trading interval (and generally new setpoints for non Verve units)	Noted.
Recommendation - Consider commissioning a detailed wind correlation study	This is not new but lack of willingness to share data has previously has prevented this outcome. This recommendation is only effective if sharing of hub height 1 minute readings can be achieved.	Text mentioning this has been added to the report.
Recommendation - Consider introduction of an efficient market for the provision of ancillary services	System Management is seeking to do this but it will also require rule changes. System Management would welcome the opportunity to share its work so far with the REGWG and the report authors and System Management's views on how this work should be progressed further.	Noted.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
Recommendation - If the load following service is explicitly split into different components, different participants should be responsible for the costs of each.	This appears consistent with the market objectives.	Noted.
Recommendation - Arduous requirements for wind farms to provide system inertia should not be applied	This is generally not applicable to load following but may be required for contingency frequency control.	ROAM agrees, although spinning reserve and load following services are closely related in their treatment in the WEM Rules, so it was felt that this was useful insight to provide within the conclusions of the study.
Recommendation - Intermittent generators must be able to curtail if necessary	It is important that sufficient installed intermittent generation (of consequence) has the facilities to curtail output if required. This is true of all generators but the challenge is to determine the curtailment order in the various timeframes in accordance with the market objectives.	This comment simply refers to the technical capability of wind farms to curtail, since as intermittent generation this capability is less obvious than with other schedulable types of generation. It is agreed that the curtailment order is a challenging problem that should be dealt with as a priority (see following point).
Recommendation - Consider implementing more transparent dispatch merit order priorities in the SWIS	The current dispatch merit order priorities in the SWIS are far from a free and transparent market. This is likely to become a very significant issue in the near future, and should be addressed as a priority. This goes to the heart of market design. It seems clear that the priority is Verve decommit first and then redispatch non-Verve plant. That is the order is based on ownership rather than an economic outcome. System Management is pleased to note that the MAC's Market Rules Working Group and the Oates review committee are looking at the economic, commercial and technical issues associated with an efficient market driven dispatch mechanism.	ROAM agrees that this should be addressed as a priority.
Recommendation - The methodology in the Rules for the determination of the costs of load following and spinning reserve should be reviewed as a priority.	The existing equations are likely to become insufficient within the next few years. Alternative equations are proposed in the body of this report that address these immediate issues.	-
Recommendation - An efficient market for frequency control ancillary services should be established	The establishment of an efficient market for load following and spinning reserve services would avoid determining the costs of providing these services via arbitrary equations with the need for constant revision of calibration factors. It would also facilitate their provision from the most cost effective source, minimising costs to participants. System Management agrees and notes that the current market rules do not always reflect an efficient market price.	Noted.
Recommendation - Investigate ways of minimising the increase in cost of load following	Introduction of an efficient market for sourcing frequency control ancillary services from the most cost effective source is likely to be an effective way of minimising the cost increase in the load following service. Methods for minimising the increase in the load following requirement should also be explored, such as methods of operating wind farms that minimise their aggregate variability.	This has been combined with other recommendations where appropriate, and elaborated upon where appropriate.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
	The first sentence seems a repeat of the above. System Management agrees with second sentence but would add that there are mature technologies available (other than operating windfarms in a way that minimises their aggregate variability) which are technically feasible in SWIS but not commercially viable under the current market arrangements.	
Recommendation - Intermittent generators should pay the marginal cost of the provision of the load following service, above that required for load variability	This appears consistent with the market objectives. This would represent a major increase in costs for the intermittent generators from the existing MWh pro rata.	ROAM agrees.
Recommendation - Ramp limits should not be applied to intermittent generators individually.	It may be effective to control aggregate ramping of intermittent generation, but this would be best achieved on a case-by-case basis by System Management as required. System Management has observed that whilst major ramp ups can occur across the windfarm fleet they are reasonably rare and normally occur when a front crosses the coast causing a high wind shutdown and a bit later a large ramp up when the wind starts to fall below the cut out level.	This is consistent with the data available to ROAM.
Recommendation - Consider investigating the various ways in which load following requirements could be reduced or managed more effectively	This could include analysis of the effectiveness and costs of the following individually, or in combination: 1. Limiting aggregate maximum ramp-up rates for wind farms 2. Varying the load following requirement depending upon the current output level of intermittent generation 3. Varying the load following requirement by time of day 4. Capping maximum output of intermittent generators 1 – System Management agrees that this suggestion is worthy of further investigation 2,3 Currently System Management normally does this by estimating the amount of gustiness over the next few hours and increasing the load following accordingly. The windfarm forecasting tool currently in use has been found to assist in this process. 4 – System Management would be concerned that this suggestion may not be in line with the market objectives	The text has been updated to reflect these suggestions.
Page 3 para 2 Load Following in the SWIS	"The existing load following Rules in the SWIS require that sufficient plant (mostly open cycle gas turbines (OCGTs)) be online to meet fluctuations in wind and demand in 99.9% of all periods." The load following is governed by two components of which only one is covered by the report. a. the Market Rules *"the capacity sufficient to cover 99.9% of the short term fluctuations in load and output of Non-Scheduled Generators and uninstructed output fluctuations from Scheduled Generators, measured as the variance of 1 minute average readings around a thirty minute rolling average. "* b. the Technical Rules	ROAM has taken both the Technical Rules and the Market Rules into account in this analysis. The Technical rules were used directly to interpret system frequency modelling, in relation to "fast response" load following requirements. This analysis suggested that the standard defined in the Market Rules is appropriate and sufficient (section 11.3 of the report). This standard has therefore been used throughout the report for cost analysis, dispatch modelling, etc. Text explaining this further for clarity has been added to section 5.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
	"Frequency operating standards for the *South West Interconnected Network* 49.8 to 50.2 Hz for 99% of the time" It is the second component that provides the sufficiency test as it is an output measurement as opposed to an input measurement. The determination of "cover" is problematic in the first definition.	
Section 5, pages 11 to 21 – Metrics for Assessing Load Following Requirements	In the current and alternate modelling there is no mention of the frequency metrics which is an essential element. This is an essential follow on from the thoughts above. The essential metric is the frequency histogram rather than the load following capacity.	As above. ROAM has added text to explain this more clearly within the report.
Section 1.1, page 1 – Ancillary Services	System Management's understanding is that the following definitions apply in WEM. 1. Frequency control service as it is called in the report is called Frequency Keeping in the Market Rules. It is also referred to as Load Following in the Market Rules. Frequency Keeping ancillary service is part of the Spinning Reserve ancillary service which also provides coverage for contingency trip of a generator. 2. Network control is not an ancillary service. It is defined as a separate service called Network Control Service in the Market Rules.	The text in the report has been updated to reflect this.
Sections 5.6 pages 17 to 21 – Slow Following Service	It appears to System Management that the magnitude and frequency of large load changes in the Slow Following, Regulation and Fast Response services may be reduced significantly if System Management's short term windfarm output forecast is used as an input.	It is likely that the load following requirements would reduce somewhat if the windfarm output forecast is reasonably accurate on the various timescales involved. It is likely to be most beneficial at the slower timeframes (slow following, and possible for regulation), and less beneficial at shorter timeframes (fast response) where a minute to minute correlation between the forecast and wind output would be required.
Section 6.1.1 pages 22 to 24 – Calibration of WEST	The section on calibration of ROAM's Wind Energy Simulation Tool (WEST) indicates that significant variance between the actual output of a windfarm and the simulated data can occur. It may also be relevant to judgement of the MMA studies into windfarm capacity credits where due to lack of actual data much of the analysis was based on simulated windfarm output.	Simulated wind farm traces are always an approximation of actual wind farm output, and the accuracy of any traces must be considered. On a minute to minute level, the simulated traces do differ substantially from the actual wind farm output in many periods. However, the traces do replicate closely the statistics used for the calculation of load following requirements, which is the important parameter for this analysis. As better data becomes available over time ROAM certainly recommends that analysis such as this is revised for continued validity.
Section 6.2 and 7.1 pages 26 to 35 – Load Forecasting and Load Following Requirements Results	System Management notes that the 2007-08 historical 1 minute basis loads were used as input to the load forecasting algorithm. Could ROAM please provide an explanation about the forecasting methodology used to forecast the variation in the load alone (in the absence of wind), and the wind alone (in the absence of demand variation) and how these components were combined to produce the total load and wind variation	Wind farm traces were calculated as outlined in section 6.1 of the report (Wind Energy Simulation Tool). One minute wind data from Bureau of Meteorology weather station sites was used as a basis for wind farm output. Load traces were calculated as outlined in section 6.2 of the report (Load Forecasting). Historical demand in 2007-08 was used as a basis for load traces projected forward (grown with annual energy and demand targets). Both traces (wind and load) were then analysed with the metrics outlined in section 5 (Metrics for Assessing Load Following Requirements). Figure 5.1 illustrates how the load deviation was calculated (separate from wind variations), and Figure 5.2 illustrates how the wind deviation was calculated (separate from load variations). The load following requirement due to variations in load and wind combined is determined by calculating a trace of "schedulable generation" by subtracting the wind from the load at each point in time. The load following requirement is then calculated as

Work Package 3 Report “Assessment of FCS and Technical Rules” (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
		outlined in section 5.1. Additional text has been added to the report to explain this more thoroughly (section 6.3).
Section 7.2 pages 32 to 42 – Proposed Alternative Definition	Could ROAM also please provide an explanation about how the forecast has been applied to the proposed alternative definitions for the slow response, regulation and fast response services.	Additional text has been added to the report to explain this more thoroughly (section 6.3).
Section 10.1.1 and 10.1.2, pages 52 to 54 – Calibrating the System Frequency Model	System Management endorses ROAMS comments on the variation between model outcomes and actual SWIS response beyond the 8 second period. A known feature of many generator facility control systems is a wind back to resource plan that takes place quickly after governor action has occurred. This is observed to cause a second stage of frequency decline some 10 or more seconds after the initial decline is arrested by the governors.	Noted.
Section 12, page 60 paragraph 1, and page 63 – Issues Associated with the Provision of Ancillary Services	Currently System Management is required to leave 2 Muja units on overnight (in addition to Collie at between 160 MW and 200 MW depending on flue gas temperatures) to provide critical restart oil heating in case one unit trips. As “must run” generation increases (including windfarms) there is an increasing likelihood that must run plant may need to be unloaded. This is likely to test the definition of “must run” plant in SWIS and could force windfarm output reduction.	Noted.
Section 13.1 and subsections, page 64 – Systems with Significant Interconnection	System Management notes that Germany and Denmark with high penetrations of windfarm have very strong transmission interconnections over which they balance windfarm energy changes and from which they draw load following capability. There are no interconnections in SWIS with frequency keeping capability. We also note that windfarm output forecasting at local and system level is becoming a critical management tool in determining balancing service requirements in both systems. System Management is moving in a similar direction and has received approval from the ERA for a windfarm forecasting tool to be integrated into SMMITS.	Germany and Denmark are grouped under the heading "Markets with Significant Interconnection" (section 3.1), and it is noted that their highly interconnected nature bears little resemblance to the isolated grid in the SWIS. However, with their pioneering high levels of wind penetration they are considered worthy of analysis. Other less highly interconnected markets are also included for their greater resemblance to the SWIS. ROAM agrees that wind forecasting is an essential tool.
Section 13.2.1, Page 67 – Markets with Low Interconnection (South Australia)	The last sentence suggests that AEMO (NEMMCO) may increase the cost to the market for procuring FCAS. Is it AEMO that would increase the cost to the market or would the price naturally rise as bid prices increased due to short supply? The report does not appear to make reference to AEMO’s ANEMOS windfarm forecasting system which we understand has a role in pre-dispatch and semi-dispatch. Could ROAM please describe how this forecast is integrated into the AEMO’s and windfarm operator’s processes.	This ambiguous wording has been changed. A section on AEMO's AWEFS system sourced from ANEMOS has been added to the report.
Section 13.2.2, page 68 (see also Section 14.3, page 71) – Markets with Low Interconnection (EIRE)	The report indicates the importance of developing an active ancillary services market to manage extensive penetration of wind. System Management feels that the report would be more balanced by the inclusion of some comment about the mechanisms involved and implications of implementing market based schemes in WEM/ SWIS.	A market approach to ancillary services including load following been generally successful in the NEM, with clearing prices in the market being much less than contract prices prior to the introduction of the FCAS market. This is discussed in section 14.6 of the report. Detailed simulation would be needed to assess the benefits to the SWIS.

Work Package 3 Report "Assessment of FCS and Technical Rules" (21/5/10) - REGWG Comments		
Issue	**Comments**	**ROAM Response**
Section 14.3, page 72 – Revised Cost Calculation	The report notes that it is possible for spinning reserve requirement to exceed the load following requirement in peak periods, but not off-peak periods. Currently in SWIS spinning reserve (70% of largest loaded unit) dominates in all intervals (peak about 220 MW less SILs, off-peak about 140 MW less SILS). It is expected that as windfarm capacity increases load following will become dominant during off-peak periods and eventually as windfarm capacities increase further as a result of MRET/ CPRS the load following requirement may be dominant over the both peak and off-peak periods.	Text elaborating on this has been added to the report.