QUARTERLY ACTIVITIES REPORT
For the quarter ended 31 March 2024

88 Energy Limited (ASX:88E, AIM:88E, OTC:EEENF) (**88 Energy, 88E** or the **Company**) provides the following report for the quarter ended 31 March 2024.

Highlights

Project Phoenix (~75% WI)

- Successful Hickory-1 discovery well flow test and stimulation program (**Flow Test**) conducted during March and April 2024.
- Upper Slope Fan System (**USFS**) produced at a peak flow rate of over 70 barrels of oil per day (bopd) of light oil, with multiple oil shows measuring ~40-degree API oil gravity.
- Subsequent to quarter end the Shelf Margin Deltaic (**SMD**) produced at a peak flow rate of ~ 50 barrels of oil per day (bopd) of light oil, with multiple oil shows measuring ~39-degree API oil gravity.
- Quality and deliverability of both SMD-B and USFS demonstrated via oil production to surface with the USFS reservoir producing under natural flow – positively differentiating Hickory-1 from results on adjacent acreage.
- It is anticipated that these reservoirs would be developed from long horizontal production wells which typically produce at multiples of between 6 to 12 times higher than vertical wells. Project Phoenix also benefits from the ability to produce concurrently from multiple reservoirs in a single development scenario.
- Independent Contingent Resource declaration to be sought for both the Upper SFS and Lower SFS reservoirs, as well as the SMD reservoirs, based on the flow of hydrocarbons to surface.
- JV Partner Burgundy Xploration, LLC (**Burgundy**) transferred remaining outstanding 2023 cash call amount due of US$1.75 million and remains committed to the Hickory-1 flow test authorised funding expenditure (AFE).

Managing Director, Ashley Gilbert, commented on Project Phoenix:

"In what has proven to be a pivotal quarter for 88 Energy and its shareholders, we achieved the successful flow of oil to surface, for the first time, from the previously untested USFS reservoir and also subsequent to quarter end from the shallower SMD-B reservoir, both at our Hickory-1 discovery well. This represents a tremendous achievement that adds immediate value to Project Phoenix and unlocks multiple pathways for future commercialisation.

With flow testing operations complete, we will now transition to post well analysis and are moving to secure further Contingent Resources at Project Phoenix.

We expect to commence a formal farm-out process for Project Phoenix following completion of the Hickory-1 post flow test analysis, with the aim of attracting a strategic partner for the next stage of development and commercialisation."

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Namibia PEL 93 (20% WI)

- Transfer of 20% working interest in Petroleum Exploration Licence 93 **(PEL 93)** complete, being the first stage of a three-stage farm-in agreement following approval by the Namibian Ministry of Mines and Energy.
- PEL 93 includes an extensive lead portfolio with ten significant independent structural closures identified from a range of geophysical and geochemical techniques and potential for more leads to be identified as dataset is expanded.
- Seismic acquisition is planned for mid-2024 with potential initial exploration well targeting the Damara play as early as H2 CY2025.

Project Leonis (100% WI)

- Maiden prospective resource estimate for Upper Schrader Bluff **(USB)** reservoir expected H1 2024.
- Farm-out process commenced with multiple parties engaged and reviewing data room materials, ahead of potential drilling of a new well in 2025/2026.

Project Longhorn (~64% WI)

- Two of the planned five workovers scheduled to be in completed in 1H 2024 are underway and are currently projected to be delivered under budget.
- Q1 2024 production steadily averaged 328 BOE per day gross (~62% oil).
- Company received cash flow distribution of A$0.7M in March 2024.
- The Company also reduced it's working interest in 9 leases during the quarter by an average of a ~7% reduction in net WI's across these leases. Consideration for these leases totalled A$0.3M.

Corporate

- Cash balance of A$17.5 million and no debt (as at 31 March 2024), ~20% of Hickory-1 flow test payments have been made, with the remainder expected to be paid in Q2 2024.
- Net cash outflows in relation to operating expenses for Q1 2024 totalling A$0.77M as compared to A$1.44M in Q4 2023.
- Cost reduction initiatives commenced in the quarter targeting a reduction in salary and overhead costs. Further business optimisation activities underway, aimed at preserving and enhancing value for shareholders and advancement of key projects.

Project Phoenix (~75% WI)

Project Phoenix is focused on oil-bearing conventional reservoirs identified during the drilling and logging of Icewine-1 and Hickory-1 and adjacent offset drilling and testing. Project Phoenix is strategically located on the Dalton Highway with the Trans-Alaskan Pipeline System running through the acreage.

The Hickory-1 discovery well was previously drilled in February 2023. All American Oilfield's upgraded Rig-111 was subsequently secured in September 2023 to conduct the flow test. During the March 2024 quarter, ice road and pad construction works were completed and the rig was subsequently mobilised. Flow test operations commenced in March 2024.

The testing operations focussed on the two primary targets, the SFS and SMD reservoirs. Of the SFS series of reservoirs, the Upper SFS reservoir was targeted to be flow tested as it has not been previously tested, whereas the Lower SFS has previously been flow tested and producibility of that reservoir confirmed on adjacent acreage. The Upper SFS was followed by a targeted testing of the SMD-B reservoir. Each zone was independently isolated, stimulated and flowed to surface using nitrogen lift to assist in an efficient clean-up of the well.

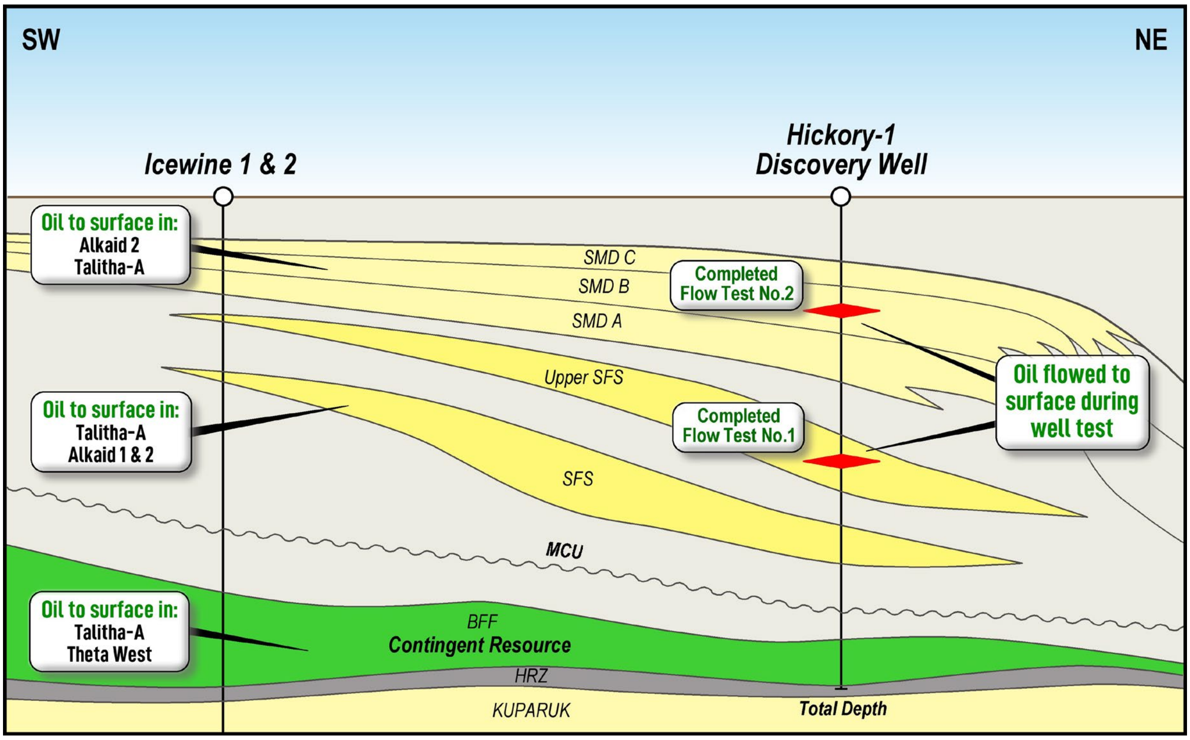
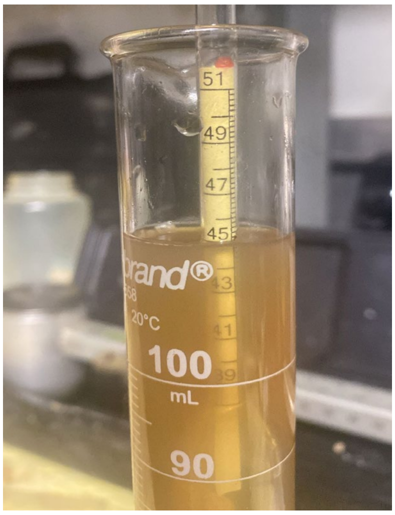


Figure 1: Hickory-1 Flow testing program flowed oil to surface from the two tested zones.

Upper SFS flow test results

A 20ft perforated interval in the Upper SFS reservoir was stimulated via a single fracture stage of 241,611 lbs proppant volume. The well was cleaned-up and flowed for 111 hours in total, of which 88 hours was under natural flow back and 23.5 hours utilising nitrogen lift.



The USFS test produced at a peak flow rate of over ~70 bopd. Oil cuts increased throughout the flow back period as the well cleaned up, reaching a maximum of 15% oil cut at the end of the flow test program. The Company expects that oil rates and cut would have likely increased further should the test period have been extended. The well produced at an average oil flow rate of approximately 42 bopd during the natural flow back period (with established production rates occurring over an ~11 hour test period, accumulating ~19bbls of oil. An additional ~6bbls of oil was recovered outside of the established production period), with instantaneous rates ranging from approximately 10 – 77 bopd with average rates increasing through the test period. Importantly, the USFS zone flowed oil to surface under natural flow, with flow back from other reservoirs in adjacent offset wells only producing under nitrogen lift. A total of 3,960bbls of fluid was injected into the reservoir and 2,882bbls of water was recovered during the flow back period, most of which was injection fluid. Total flow rates (inclusive of recovery of frac fluid) averaged ~600 bbl/d over the duration of the flow back.

Multiple oil samples were recovered with measured oil gravities of between 39.9 to 41.4 API (representing a light crude oil).

Additionally, some natural gas liquids (“NGLs”) were produced but not measured, as was anticipated in the planning phase. The presence of NGLs was demonstrated by samples from the flare line and by visible black smoke in the flare. Historically, NGL prices on the North Slope of Alaska have been similar or slightly below light oil prices and are therefore considered highly valuable. Further work is required to quantify the exact volume of NGLs, which 88 Energy intends to include as part of a maiden certified Contingent Resource assessment at Project Phoenix for the SFS reservoirs.

For full details in relation to the Upper SFS test results please refer to the ASX announcement dated 2 April 2024.

SMD-B flow test results (subsequent to quarter end)

A 20ft perforated interval in the SMD-B reservoir was stimulated via a single fracture stage comprising 226,967 lbs of proppant volume. The well was cleaned-up and flowed for 84 hours in total, utilising nitrogen lift throughout the entire test period. The average fluid flow rate over the duration of the flow back period was approximately 445 bbls/d, with choke sizes ranging from 8/64ths to 33/64ths.

The SMD-B test produced at a peak estimated flow rate of ~50 bopd. Oil cuts varied throughout the flow back period, reaching a maximum of 10% oil cut. The well produced at an average oil cut of 4% following initial oil to surface, with instantaneous rates observed during the 16-hour period varying as the well continued to clean up. Total stimulation load water was not recovered and water salinity measurements indicated we were recovering load water at the conclusion of the test. Unlike flow tests on adjacent acreage where multiple gas lift mandrels and valves were used in completions designs, and nitrogen was unloaded in the tubing in stages up the well bore, Hickory-1 utilised a single gas lift mandrel where nitrogen was introduced via one valve at the deepest section. This is viewed as positive indication for future potential rates and performance.

Multiple oil samples were recovered, with measured oil gravities of between 38.5 to 39.5 API, representing a light crude oil.

Importantly, the SMD-B zone flowed oil to surface with little to no measurable gas, representing a low GoR production rate. Pressurised oil samples collected during both the USFS and SMD tests will be transported to laboratories for further analysis.

The SMD-B flow test was concluded with sufficient information for the next steps, and the data recorded will assist 88E in optimisation and design processes in the next phase of advancement of Project Phoenix.

For full details in relation to the SMD-B test results please refer to the ASX announcement dated 15 April 2024.

Namibia PEL 93 (20% WI)

In February 2024, the Company announced the successful 20% WI transfer by Monitor Exploration Limited (**Monitor**) to 88 Energy in relation to PEL 93 located in the Owambo Basin, Namibia following receipt approval from the Ministry of Mines and Energy.

The Company, via its wholly-owned Namibian subsidiary, previously executed a three-stage farm-in agreement in November 2023 for up to a 45% non-operated working interest in onshore Petroleum Exploration Licence (PEL 93), which covers 18,500km^2 of underexplored ground within the Owambo Basin in Namibia (refer to ASX announcement dated 13 November 2023).

Under the terms of the agreement, 88 Energy may earn up to a 45% working interest by funding its share of agreed costs under the 2023-2024 approved work program and budget as defined in the Farm-In Agreement (2024 Work Program) and any future work program budgets yet to be agreed. The maximum total investment by the Company is anticipated to be US$18.7 million.

The current and potential future PEL 93 Joint Venture partners and working interests are as follows:

Entity	Pre Farm-in	Stage 1 - Current (Past costs & 2D)	Stage 2 (1st Well)	Stage 3 (2nd Well)
Monitor*	75.0%	**55.0%**	37.5%	30.0%
Legend	15.0%	**15.0%**	15.0%	15.0%
NAMCOR	10.0%	**10.0%**	10.0%	10.0%
88 Energy	**-**	**20.0%**	**37.5%**	**45.0%**

**Operator*

Namibia has been identified as one of the last remaining under-explored onshore frontier basins and one of the World's most prospective new exploration zones. PEL 93 is more than 10 times larger than 88 Energy's Alaskan portfolio and more than 70 times larger than Project Phoenix.

Recent drilling results on nearby acreage has highlighted the potential of a new and underexplored conventional oil and gas play in the Damara Fold belt, referred to as the Damara Play. Historical assessment utilised a combination of techniques and interpretation of legacy data to identify the Owambo Basin, and specifically blocks 1717 and 1817, as having significant exploration potential.

Monitor has utilised a range of geophysical and geochemical techniques to assess and validate the significant potential of the acreage since award of PEL 93 in 2018. It has identified ten (10) independent structural closures from airborne geophysical methods and partly verified these using existing 2D seismic coverage. Further, ethane concentration measured in soil samples over interpreted structural leads validates the existence of an active petroleum system, with passive seismic anomalies also aligning closely to both interpreted structural leads and measured alkane molecules (c1-c5) concentrations in soil.

The forward work-program will start with a low impact ~200 line-kilometre 2D seismic program focusing on confirming the structural closures of the 10 independent leads identified. The 2D seismic program will be conducted in mid-2024 following a period of planning, public consultation, updating of environmental compliance requirements and relevant approvals. Results from the 2D seismic program will then be incorporated into existing historical exploration data over the acreage, with results used to identify possible exploration drilling locations.

Project Longhorn (~65% WI)

In December 2023, the Joint Venture (**Bighorn JV**), Bighorn Energy LLC (**Bighorn**) which comprises Longhorn Energy Investments LLC (**LEI**) a 100% wholly owned subsidiary of 88 Energy with 75% ownership and Lonestar I, LLC (**Lonestar** or **Operator**) with remaining 25% ownership, finalised its 2024 work program and budget. The Bighorn JV agreed to a development program that included 5 workovers in 1H 2024 and 2 new wells in 2H 2024, contingent on successful workovers.

During the quarter, the Bighorn JV commenced two of the planned five workovers with assessment of production occuring during April 2024.

Q1 2024 production averaged a fairly steady 328 BOE per day gross (~62% oil) which was slightly below the budgeted volume of 346 BOE per day gross (65% oil) due to January winter storms and the Company received a cash flow distribution of A$0.7M in March 2024.

The Bighorn JV executed a ~10% sell-down (gross, ~7% net to 88 Energy) of the 2023 acquired acreage, in order to re-disk and accelerate development opportunities. The transaction realised acquisition payments of ~A$0.3M and the non-operated partners will contribute their share of the capital development costs coupled with a 25% carry of their ownership share on the five 2024 WP&B agreed workovers.

UPDATED RESERVES RECONCILIATION AS AT 31 MARCH 2024, 88 ENERGY NET ENTITLEMENT

Reserves Reconciliation		Net Oil (MMBO)				Net Gas (BCF)				Net Oil Equivalent (MMBOE)			
		YE 2023	Q1'24 Prod	Tech Rev	31/3/ 2024	YE 2023	Q1'24 Prod	Tech Rev	31/3/ 2024	YE 2023	Q1'24 Prod	Tech Rev	31/3/ 2024
Proved Total	1P	1.43	(0.011)	(0.04)	1.43	3.04	(0.038)	(0.04)	2.97	1.94	(0.019)	(0.05)	1.87
Proved + Probable	2P	1.91	(0.011)	(0.05)	1.91	4.27	(0.038)	(0.06)	4.17	2.62	(0.019)	(0.06)	2.55
Proved + Probable + Possible	3P	2.57	(0.011)	(0.07)	2.57	5.88	(0.038)	(0.08)	5.76	3.55	(0.019)	(0.08)	3.45

Qualified Petroleum Reserves Evaluator Statement

The information in this evaluation that relates to Project Longhorn is based on, and fairly represents, information and supporting documentation prepared by Paul Griffith of consultants PJG Petroleum Engineers LLC. Mr Griffith holds a BSc. and a Master's in Petroleum Engineering, is a member of the Society of Petroleum Engineers (SPE) and has over 35 years of reservoir and petroleum engineering experience. Mr Griffith is not an employee of the Company. Mr Griffith has reviewed this document as to its form and context in which the reserves and the supporting information are presented and consent to its release.

The information in this evaluation that relates to the Umiat oil field has not changed since first reporting to the ASX on 11 January 2021, and fairly represents, information and supporting documentation prepared by technical employees of consultants Ryder Scott Company LP, under the supervision of Dr Stephen Staley, as stated in that announcement. Dr Staley is a Non-Executive Director of the Company. Dr Staley has more than 40 years' experience in the petroleum industry, is a Fellow of the Geological Society of London, and a qualified Geologist/Geophysicist who has sufficient experience that is relevant to the style and nature of the oil prospects under consideration and to the activities discussed in this document. Dr Staley has reviewed the information and supporting documentation referred to in this announcement and considers the resource and reserve estimates to be fairly represented and consents to its release in the form and context in which it appears. His academic qualifications and industry memberships appear on the Company's website and both comply with the criteria for "Competence" under clause 3.1 of the Valmin Code 2015.

Reserves Cautionary Statement

Oil and gas reserves and resource estimates are expressions of judgment based on knowledge, experience and industry practice. Estimates that were valid when originally calculated may alter significantly when new information or techniques become available. Additionally, by their very nature, reserve and resource estimates are imprecise and depend to some extent on interpretations, which may prove to be inaccurate. As further information becomes available through additional drilling and analysis, the estimates are likely to change. This may result in alterations to development and production plans which may, in turn, adversely impact the Company’s operations. Reserves estimates and estimates of future net revenues are, by nature, forward looking statements and subject to the same risks as other forward-looking statements.

Corporate

The Company held a General Meeting on 15 January 2024 and all 11 resolutions were passed without amendment on a poll.

Finance

As at 31 March 2024, the Company’s cash balance is A$17.5M.

The ASX Appendix 5B attached to this quarterly report contains the Company’s cash flow statement for the quarter. The material cash flows for the period were:

- Exploration and evaluation expenditure of A$3.9M (December 2023 quarter: A$2.8M) predominantly related to the Hickory-1 flow test program. Approximately 20% of Hickory-1 flow test payments have been made, with the remainder expected to be paid in Q2 2024.
- Administration, staff, and other costs of A$0.7M (December 2023 quarter: A$1.4M). Including fees paid to Directors and consulting fees paid to Directors of A$0.2M.
- Cost reduction initiatives commenced in the quarter targeting a reduction in salary and overhead costs. Further business optimisation activities underway, aimed at preserving and enhancing value for shareholders and advancement of key projects.

Information required by ASX Listing Rule 5.4.3

Project Name	Location	Net Area (acres)	Interest at beginning of Quarter	Interest at end of Quarter
Project Phoenix	Onshore, North Slope Alaska	62,324	~75%	~75%
Project Icewine West	Onshore, North Slope Alaska	121,996	~75%	~75%
Project Peregrine[1]	Onshore, North Slope Alaska (NPR-A)	125,735	100%	100%
Project Longhorn	Onshore, Permian Basin Texas	2,830	~63%	~65%
Project Leonis	Onshore, North Slope Alaska	25,431	100%	100%
Umiat Unit	Onshore, North Slope Alaska (NPR-A)	17,633	100%	100%
Namibia[2]	Onshore, Owambo Basin, Namibia	914,270	0%	20%

Pursuant to the requirements of the ASX Listing Rules Chapter 5 and the AIM Rules for Companies, the technical information and resource reporting contained in this announcement was prepared by, or under the supervision of, Dr Stephen Staley, who is a Non-Executive Director of the Company. Dr Staley has more than 40 years' experience in the petroleum industry, is a Fellow of the Geological Society of London, and a qualified Geologist / Geophysicist who has sufficient experience that is relevant to the style and nature of the oil prospects under consideration and to the activities discussed in this document. Dr Staley has reviewed the information and supporting documentation referred to in this announcement and considers the prospective resource estimates to be fairly represented and consents to its release in the form and context in which it appears. His academic qualifications and industry memberships appear on the Company's website, and both comply with the criteria for "Competence" under clause 3.1 of the Valmin Code 2015. Terminology and standards adopted by the Society of Petroleum Engineers "Petroleum Resources Management System" have been applied in producing this document.

This announcement has been authorised by the Board.

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1. *Refer announcement released to ASX on 21 December 2023 regarding Project Peregrine 12-month suspension until 30 November 2024*

Information required by ASX Listing Rule 5.4.3 – Lease Schedules as at 31 March 2024

Project Phoenix

Sub-Project	Entity	ADL	Gross Acres	WI	Net Acres
Toolik River Unit	Accumulate Energy Alaska, Inc	392296	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392297	1,351	69.1%	934
Toolik River Unit	Accumulate Energy Alaska, Inc	392300	1,351	69.1%	934
Toolik River Unit	Accumulate Energy Alaska, Inc	392303	1,431	69.1%	989
Toolik River Unit	Accumulate Energy Alaska, Inc	392304	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392305	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392306	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392307	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392308	1,431	69.1%	989
Toolik River Unit	Accumulate Energy Alaska, Inc	392309	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392310	1,437	69.1%	993
Toolik River Unit	Accumulate Energy Alaska, Inc	392311	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392312	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392313	1,440	69.1%	995
Toolik River Unit	Accumulate Energy Alaska, Inc	392314	1,431	69.1%	989
Toolik River Unit	Accumulate Energy Alaska, Inc	392315	1,437	69.1%	993
Toolik River Unit	Accumulate Energy Alaska, Inc	392756	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392759	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392770	1,356	77.5%	1,052
Toolik River Unit	Accumulate Energy Alaska, Inc	392771	1,362	77.5%	1,056
Toolik River Unit	Accumulate Energy Alaska, Inc	392773	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392779	1,437	77.5%	1,114
Toolik River Unit	Accumulate Energy Alaska, Inc	392780	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392781	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392782	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392783	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392784	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392785	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392298	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392299	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392301	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392302	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392541	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	392540	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	393131	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	393133	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	393078	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	393079	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	393080	1,440	77.5%	1,117
Toolik River Unit	Accumulate Energy Alaska, Inc	393087	1,356	77.5%	1,052
Toolik River Unit	Accumulate Energy Alaska, Inc	393089	1,362	77.5%	1,056
Toolik River Unit	Accumulate Energy Alaska, Inc	393090	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393081	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393083	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393085	1,351	77.5%	1,048
Phoenix East	Accumulate Energy Alaska, Inc	393086	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393088	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393091	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393132	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393134	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393139	1,420	77.5%	1,101
Phoenix East	Accumulate Energy Alaska, Inc	393140	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393141	1,425	77.5%	1,105
Phoenix East	Accumulate Energy Alaska, Inc	393142	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393143	1,431	77.5%	1,110
Phoenix East	Accumulate Energy Alaska, Inc	393144	1,440	77.5%	1,117
Phoenix East	Accumulate Energy Alaska, Inc	393145	1,437	77.5%	1,114
Phoenix East	Accumulate Energy Alaska, Inc	393146	1,440	77.5%	1,117
Total Project Phoenix			**82,846**	**75.2%**	**62,324**

Project Icewine West

Sub-Project	Entity	ADL	Gross Acres	WI	Net Acres
Icewine West	Accumulate Energy Alaska, Inc	393042	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393043	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393044	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393045	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393046	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393047	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393048	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393049	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393050	1,351	75.0%	1,013
Icewine West	Accumulate Energy Alaska, Inc	393051	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393052	1,356	75.0%	1,017
Icewine West	Accumulate Energy Alaska, Inc	393053	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393054	1,362	75.0%	1,022
Icewine West	Accumulate Energy Alaska, Inc	393055	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393056	1,367	75.0%	1,025
Icewine West	Accumulate Energy Alaska, Inc	393057	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393058	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393059	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393060	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393061	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393066	1,351	75.0%	1,013
Icewine West	Accumulate Energy Alaska, Inc	393067	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393068	1,356	75.0%	1,017
Icewine West	Accumulate Energy Alaska, Inc	393069	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393070	1,362	75.0%	1,022
Icewine West	Accumulate Energy Alaska, Inc	393071	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393072	1,367	75.0%	1,025
Icewine West	Accumulate Energy Alaska, Inc	393073	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393103	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393104	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393105	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393106	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393107	1,431	75.0%	1,073
Icewine West	Accumulate Energy Alaska, Inc	393108	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393109	1,437	75.0%	1,078
Icewine West	Accumulate Energy Alaska, Inc	393110	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393591	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393592	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393593	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393594	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393595	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393596	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393597	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393598	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393599	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393600	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393601	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393602	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	ASRC-3	5,760	75.0%	4,320
Icewine West	Accumulate Energy Alaska, Inc	ASRC-4	5,586	75.0%	4,190
Icewine West	Accumulate Energy Alaska, Inc	ASRC-5	5,760	75.0%	4,320

Sub-Project	Entity	ADL	Gross Acres	WI	Net Acres
Icewine West	Accumulate Energy Alaska, Inc	393201	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393202	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393211	1,374	75.0%	1,031
Icewine West	Accumulate Energy Alaska, Inc	393212	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393361	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393362	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393363	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393364	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393365	1,362	75.0%	1,022
Icewine West	Accumulate Energy Alaska, Inc	393366	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393367	1,367	75.0%	1,025
Icewine West	Accumulate Energy Alaska, Inc	393368	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393466	1,431	75.0%	1,073
Icewine West	Accumulate Energy Alaska, Inc	393467	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393468	1,437	75.0%	1,078
Icewine West	Accumulate Energy Alaska, Inc	393469	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393207	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393208	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393221	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393222	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393225	1,374	75.0%	1,031
Icewine West	Accumulate Energy Alaska, Inc	393226	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393237	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393238	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393241	1,374	75.0%	1,031
Icewine West	Accumulate Energy Alaska, Inc	393242	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393253	1,440	77.5%	1,117
Icewine West	Accumulate Energy Alaska, Inc	393254	1,440	77.5%	1,117
Icewine West	Accumulate Energy Alaska, Inc	393257	1,374	75.0%	1,031
Icewine West	Accumulate Energy Alaska, Inc	393258	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393369	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393370	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393371	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393372	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393373	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393374	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393375	1,351	75.0%	1,013
Icewine West	Accumulate Energy Alaska, Inc	393376	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393377	1,356	75.0%	1,017
Icewine West	Accumulate Energy Alaska, Inc	393378	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393379	1,362	75.0%	1,022
Icewine West	Accumulate Energy Alaska, Inc	393380	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393381	1,367	75.0%	1,025
Icewine West	Accumulate Energy Alaska, Inc	393382	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393383	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393384	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393470	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393471	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393472	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393473	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393474	1,431	75.0%	1,073
Icewine West	Accumulate Energy Alaska, Inc	393475	1,440	75.0%	1,080
Icewine West	Accumulate Energy Alaska, Inc	393476	1,437	75.0%	1,078
Icewine West	Accumulate Energy Alaska, Inc	393477	1,440	75.0%	1,080
Total Project Icewine West			**162,563**	**75.0%**	**121,996**

Project Peregrine

Sub-Project	Entity	ADL	Gross Acres	WI	Net Acres
Harrier-1	Emerald House LLC	095396	11,432	100.0%	11,432
Harrier-1	Emerald House LLC	095397	11,410	100.0%	11,410
Harrier-1	Emerald House LLC	095398	11,409	100.0%	11,409
Harrier-1	Emerald House LLC	095401	11,381	100.0%	11,381
Harrier-1	Emerald House LLC	095402	11,386	100.0%	11,386
Harrier-1	Emerald House LLC	095607	11,351	100.0%	11,351
Merlin-1	Emerald House LLC	095392	11,478	100.0%	11,478
Merlin-1	Emerald House LLC	095393	11,456	100.0%	11,456
Merlin-1	Emerald House LLC	095604	11,497	100.0%	11,497
Merlin-1	Emerald House LLC	095605	11,479	100.0%	11,479
Merlin-1	Emerald House LLC	095606	11,456	100.0%	11,456
Total Project Peregrine			**125,735**	**100.0%**	**125,735**

Project Umiat

Sub-Project	Entity	ADL	Gross Acres	WI	Net Acres
Umiat Unit	Emerald House, LLC	081726	6,133	100.0%	6,133
Umiat Unit	Emerald House, LLC	084141	11,500	100.0%	11,500
Total Project Umiat			**17,633**	**100.0%**	**17,633**

Project Leonis

Sub-Project	Entity	ADL	Gross Acres	WI	Net Acres
Leonis	Captivate Energy Alaska, Inc	394125	2,560	100.0%	2,560
Leonis	Captivate Energy Alaska, Inc	394126	2,439	100.0%	2,439
Leonis	Captivate Energy Alaska, Inc	394134	2,560	100.0%	2,560
Leonis	Captivate Energy Alaska, Inc	394135	2,560	100.0%	2,560
Leonis	Captivate Energy Alaska, Inc	394136	2,560	100.0%	2,560
Leonis	Captivate Energy Alaska, Inc	394137	2,560	100.0%	2,560
Leonis	Captivate Energy Alaska, Inc	394138	2,560	100.0%	2,560
Leonis	Captivate Energy Alaska, Inc	394139	2,533	100.0%	2,533
Leonis	Captivate Energy Alaska, Inc	394140	2,544	100.0%	2,544
Leonis	Captivate Energy Alaska, Inc	394142	2,555	100.0%	2,555
Total Project Leonis			**25,431**	**100.0%**	**25,431**

Project Longhorn

Sub-Project	Entity	Lease	Gross Acres	WI	Net Acres
Bighorn	Longhorn Energy Investments LLC	WTAMU	125	75.0%	94
Bighorn	Longhorn Energy Investments LLC	BK	275	75.0%	206
Bighorn	Longhorn Energy Investments LLC	Univ A	331	75.0%	248
Bighorn	Longhorn Energy Investments LLC	Univ 35A	165	75.0%	124
Bighorn	Longhorn Energy Investments LLC	Univ BB	165	67.3%	111
Bighorn	Longhorn Energy Investments LLC	Cowden	165	69.3%	114
Bighorn	Longhorn Energy Investments LLC	Univ EE	52	69.4%	36
Bighorn	Longhorn Energy Investments LLC	Hill State	41	72.9%	30
Bighorn	Longhorn Energy Investments LLC	Cummins P	320	68.3%	219
Bighorn	Longhorn Energy Investments LLC	Cummins K	320	34.1%	109
Bighorn	Longhorn Energy Investments LLC	TXL P	80	34.1%	27
Bighorn	Longhorn Energy Investments LLC	NW4, Sec 9	160	5.7%	9
Bighorn	Longhorn Energy Investments LLC	Cowden RB	560	70.5%	395
Bighorn	Longhorn Energy Investments LLC	Cummins HE	80	43.8%	35
Bighorn	Longhorn Energy Investments LLC	Edwards	160	73.1%	117
Bighorn	Longhorn Energy Investments LLC	GNDU	840	67.6%	568
Bighorn	Longhorn Energy Investments LLC	Scharbauer	320	75.0%	240
Bighorn	Longhorn Energy Investments LLC	Parker	160	75.0%	120
Bighorn	Longhorn Energy Investments LLC	Red Dog	40	68.3%	27
Total Project Longhorn			**4,359**	**64.9%**	**2,830**

Appendix 5B

Mining exploration entity or oil and gas exploration entity quarterly cash flow report

Name of entity
88 Energy Limited

ABN	Quarter ended ("current quarter")
80 072 964 179	31 March 2024

Consolidated statement of cash flows		Current quarter $A'000	Year to date (3 months) $A'000
1.	**Cash flows from operating activities**		
1.1	Receipts from customers	-	-
1.2	Payments for		
	(a) exploration & evaluation	-	-
	(b) development	-	-
	(c) production	-	-
	(d) staff costs	(399)	(399)
	(e) administration and corporate costs	(406)	(406)
1.3	Dividends received (see note 3)	-	-
1.4	Interest received	37	37
1.5	Interest and other costs of finance paid	-	-
1.6	Income taxes paid	-	-
1.7	Government grants and tax incentives	-	-
1.8	Other	-	-
1.9	**Net cash from / (used in) operating activities**	**(768)**	**(768)**

2.	**Cash flows from investing activities**		
2.1	Payments to acquire or for:		
	(a) entities	-	-
	(b) tenements	(153)	(153)
	(c) property, plant and equipment	-	-
	(d) exploration & evaluation	(3,851)	(3,851)
	(e) investments	-	-
	(f) other non-current assets	-	-

Consolidated statement of cash flows		Current quarter $A'000	Year to date (3 months) $A'000
2.2	Proceeds from the disposal of:		
	(a) entities	-	-
	(b) tenements	-	-
	(c) property, plant and equipment	-	-
	(d) investments	-	-
	(e) other non-current assets	-	-
2.3	Cash flows from loans to other entities	-	-
2.4	Dividends received (see note 3)	-	-
2.5	Other - Joint Venture Contributions	2,874	2,874
	Other - Distribution from Project Longhorn	715	715
	Other – Return of Bond	-	-
2.6	**Net cash from / (used in) investing activities**	**(415)**	**(415)**

3.	**Cash flows from financing activities**		
3.1	Proceeds from issues of equity securities (excluding convertible debt securities)	-	-
3.2	Proceeds from issue of convertible debt securities	-	-
3.3	Proceeds from exercise of options	-	-
3.4	Transaction costs related to issues of equity securities or convertible debt securities	-	-
3.5	Proceeds from borrowings	-	-
3.6	Repayment of borrowings	-	-
3.7	Transaction costs related to loans and borrowings	-	-
3.8	Dividends paid	-	-
3.9	Other (provide details if material)	-	-
3.10	**Net cash from / (used in) financing activities**	**-**	**-**

4.	**Net increase / (decrease) in cash and cash equivalents for the period**		
4.1	Cash and cash equivalents at beginning of period	18,183	18,183
4.2	Net cash from / (used in) operating activities (item 1.9 above)	(768)	(768)
4.3	Net cash from / (used in) investing activities (item 2.6 above)	(415)	(415)

Consolidated statement of cash flows		**Current quarter $A'000**	**Year to date (3 months) $A'000**
4.4	Net cash from / (used in) financing activities (item 3.10 above)	-	-
4.5	Effect of movement in exchange rates on cash held	502	502
4.6	**Cash and cash equivalents at end of period**	**17,502**	**17,502**

5.	**Reconciliation of cash and cash equivalents** at the end of the quarter (as shown in the consolidated statement of cash flows) to the related items in the accounts	**Current quarter $A'000**	**Previous quarter $A'000**
5.1	Bank balances	17,502	18,182
5.2	Call deposits	-	-
5.3	Bank overdrafts	-	-
5.4	Other (provide details)	-	-
5.5	**Cash and cash equivalents at end of quarter (should equal item 4.6 above)**	**17,502**	**18,182**

6.	**Payments to related parties of the entity and their associates**	**Current quarter $A'000**
6.1	Aggregate amount of payments to related parties and their associates included in item 1	214
6.2	Aggregate amount of payments to related parties and their associates included in item 2	-

Note: if any amounts are shown in items 6.1 or 6.2, your quarterly activity report must include a description of, and an explanation for, such payments.

6.1 Payments relate to Director and consulting fees paid to Directors. All transactions involving directors and associates were on normal commercial terms.

7.	**Financing facilities** *Note: the term "facility' includes all forms of financing arrangements available to the entity.* *Add notes as necessary for an understanding of the sources of finance available to the entity.*	**Total facility amount at quarter end $US'000**	**Amount drawn at quarter end $US'000**
7.1	Loan facilities	-	-
7.2	Credit standby arrangements	-	-
7.3	Other (please specify)	-	-
7.4	**Total financing facilities**	-	-

7.5	**Unused financing facilities available at quarter end**	-
7.6	Include in the box below a description of each facility above, including the lender, interest rate, maturity date and whether it is secured or unsecured. If any additional financing facilities have been entered into or are proposed to be entered into after quarter end, include a note providing details of those facilities as well.	

8.	**Estimated cash available for future operating activities**	**$A'000**
8.1	Net cash from / (used in) operating activities (item 1.9)	(768)
8.2	(Payments for exploration & evaluation classified as investing activities) (item 2.1(d))	(3,851)
8.3	Total relevant outgoings (item 8.1 + item 8.2)	(4,619)
8.4	Cash and cash equivalents at quarter end (item 4.6)	17,502
8.5	Unused finance facilities available at quarter end (item 7.5)	-
8.6	Total available funding (item 8.4 + item 8.5)	17,502
8.7	**Estimated quarters of funding available (item 8.6 divided by item 8.3)**	3.8

Note: if the entity has reported positive relevant outgoings (ie a net cash inflow) in item 8.3, answer item 8.7 as "N/A". Otherwise, a figure for the estimated quarters of funding available must be included in item 8.7.

8.8 If item 8.7 is less than 2 quarters, please provide answers to the following questions:

8.8.1 Does the entity expect that it will continue to have the current level of net operating cash flows for the time being and, if not, why not?

Answer: n/a

8.8.2 Has the entity taken any steps, or does it propose to take any steps, to raise further cash to fund its operations and, if so, what are those steps and how likely does it believe that they will be successful?

Answer: n/a

8.8.3 Does the entity expect to be able to continue its operations and to meet its business objectives and, if so, on what basis?

Answer: n/a

Note: where item 8.7 is less than 2 quarters, all of questions 8.8.1, 8.8.2 and 8.8.3 above must be answered.

Compliance statement

1 This statement has been prepared in accordance with accounting standards and policies which comply with Listing Rule 19.11A.

2 This statement gives a true and fair view of the matters disclosed.

Date: 18 April 2024

Authorised by: By the Board
(Name of body or officer authorising release – see note 4)

Notes

1. This quarterly cash flow report and the accompanying activity report provide a basis for informing the market about the entity's activities for the past quarter, how they have been financed and the effect this has had on its cash position. An entity that wishes to disclose additional information over and above the minimum required under the Listing Rules is encouraged to do so.
2. If this quarterly cash flow report has been prepared in accordance with Australian Accounting Standards, the definitions in, and provisions of, *AASB 6: Exploration for and Evaluation of Mineral Resources* and *AASB 107: Statement of Cash Flows* apply to this report. If this quarterly cash flow report has been prepared in accordance with other accounting standards agreed by ASX pursuant to Listing Rule 19.11A, the corresponding equivalent standards apply to this report.
3. Dividends received may be classified either as cash flows from operating activities or cash flows from investing activities, depending on the accounting policy of the entity.
4. If this report has been authorised for release to the market by your board of directors, you can insert here: "By the board". If it has been authorised for release to the market by a committee of your board of directors, you can insert here: "By the [*name of board committee – eg Audit and Risk Committee*]". If it has been authorised for release to the market by a disclosure committee, you can insert here: "By the Disclosure Committee".
5. If this report has been authorised for release to the market by your board of directors and you wish to hold yourself out as complying with recommendation 4.2 of the ASX Corporate Governance Council's *Corporate Governance Principles and Recommendations*, the board should have received a declaration from its CEO and CFO that, in their opinion, the financial records of the entity have been properly maintained, that this report complies with the appropriate accounting standards and gives a true and fair view of the cash flows of the entity, and that their opinion has been formed on the basis of a sound system of risk management and internal control which is operating effectively.