Primary Growth Drivers

Volume growth over the next two years is primarily driven from re-developed mature assets (Ekofisk II) as well as from the bringing on-line of several growth projects in both the UK and Norway. However, the longer-term viability of North Sea production growth is most strongly correlated with the successful (i.e. timely) development of the massive Johan Sverdrup field which was recently sanctioned in February. We estimate North Sea crude production to hold broadly flat (~2.5 MMb/d) through 2016 before declining to 2.2 MMb/d in 2019 w/ recovery in 2020 as Johan Sverdrup is brought on-line.

Primary Risks

In our view, the impact of project delays is mostly muted as all growth projects are currently either on-stream or under development with growth from the currently producing Ekofisk field alone, estimated at ~15% of 2014-2016 North Sea. Post 2016, we expect a decline in the North Sea until the end of the decade/ramp of the massive Johan Sverdrup field (+300 Mb/d of production growth in 2020). The chief risk to North Sea production on a go-forward basis will focus on managing declines. We note, however, that Statoil (covered by our European counterparts), alone, accounts for ~20% of the oil production growth from the North Sea over the next 3 years and any announcements of a change to the company's planned activity in the region would likely have a material impact on the forecast.

<u>Managing Declines:</u> For a more detail look at North Sea decline, please see our case study on page 20 of this publication. In summary, we assume a decline rate (ex growth rates and redevelopment projects) of ~12% during our forecast period and assume a contribution of ~3% from prior year production in normalized outages within the forecasted 12% forecast. We see some upside to our forecasted decline rates as operators (in the Norwegian North Sea) benefit from exchange rate tail-winds that will soften cuts to brown field spending. Assuming that ~20% of a company's NCS spend is denominated in the local currency ($ Kroner), we estimate that a 25% YoY reduction in $USD denominated capex (proxy for an industry average) will likely result in an "actual" 10% YoY cut spend. Further, a reallocation of capital away from more costly frontier plays in the Barents Sea towards more immediate cash flow accretive brown-field projects can also provide upside to our current forecast. On our base case assumes declines of 12%, and estimate a 1% revision to the assumed decline to result in a swing of ~ 125 Mb/d to our 2017 outlook.

Figure 119: Key Growth Projects, 2014-2020

Project	IEA Region	Country	Sector	Operator	Project Type	Dev Status	API	Prod Start Up Yr	Peak Prod Yr	2014-2017 Prod	2014-2020 Prod
Edvard Grieg	Europe	Norway	Central North Sea	Lundin Petroleum	Shallow	Under Development	35	2015	2016	89	34
Laggan & Tormore Area	Europe	UK	Atlantic Margin	Total	DW	Under Development	40	2015	2018	81	91
Goliat Area	Europe	Norway	Barents Sea	Eni	DW	Under Development	36.5	2015	2016	72	35
Ekofisk Area II	Europe	Norway	Central North Sea	ConocoPhillips	Shallow	Onstream	39.6	1999	2002	68	37
Golden Eagle Area	Europe	UK	Central North Sea	Nexen	Shallow	Onstream	37.5	2014	2017	60	24
Mariner	Europe	UK	Northern North Sea	Statoil	Shallow	Under Development	13	2017	2019	52	58
Western Isles Project	Europe	UK	Northern North Sea	Dana Petroleum	Shallow	Under Development	34.5	2016	2017	33	11
Ivar Aasen Area	Europe	Norway	Central North Sea	Det Norske	Shallow	Under Development	37	2016	2020	32	62
Knarr Area	Europe	Norway	Northern North Sea	BG	DW	Under Development	45	2015	2015	27	13
Hejre	Europe	Other North Sea	Central North Sea	DONG Energy	Shallow	Under Development	43	2017	2017	27	27

Source: Deutsche Bank, Wood Mackenzie