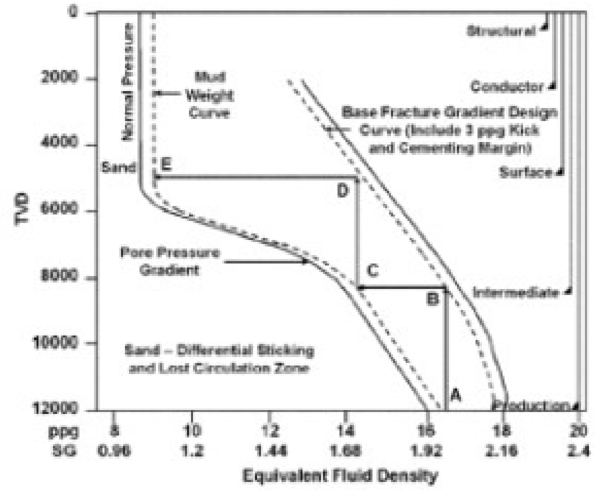

Figure 7.1. Casing Setting Depth Diagram

2. Draw the (minimum) drilling fluid density curve. The drilling fluid density curve should include a (usually) 0.3-0.5 ppg trip margin. Specific areas may incorporate different rules for drilling fluid density trip margin (surge or other overbalance), and riser margin [3] (where applicable).

3. Draw the predicted fracture gradient curve. Draw a fracture gradient design curve, which parallels the predicted fracture gradient curve with a (usually) 0.3–0.5 ppg reduction as an approximate allowance for swab during pipe movement, well control and ECD during cementing.

4. Plot offset drilling fluid densities and LOTs to provide a check of the pore pressure predictions or highlight the need for further investigation.

5. The sequence above assumes a vertical wellbore, where the acceptable equivalent drilling fluid density range is determined by pore pressure (*e.g.*, avoid fluid influx) and fracture gradient (*e.g.*, avoid rock tensile failure and associated fluid efflux). An important exception to this assumption, particularly applicable to deviated wellbores, is the consideration of wellbore stability. In some instances, mechanical instability of the wellbore wall may precede pore fluid influx and further limit the acceptable equivalent drilling fluid density range. Wellbore stability should always be a consideration, but is beyond the scope of this discussion. Consult a relevant specialist.

Once the equivalent drilling fluid density range has been established, to determine initial estimates of

3. Draw the predicted fracture gradient curve. Draw a fracture gradient design curve, which parallels the predicted fracture gradient curve with a (usually) 0.3–0.5 ppg reduction as an approximate allowance for swab during pipe movement, well control and ECD during cementing.

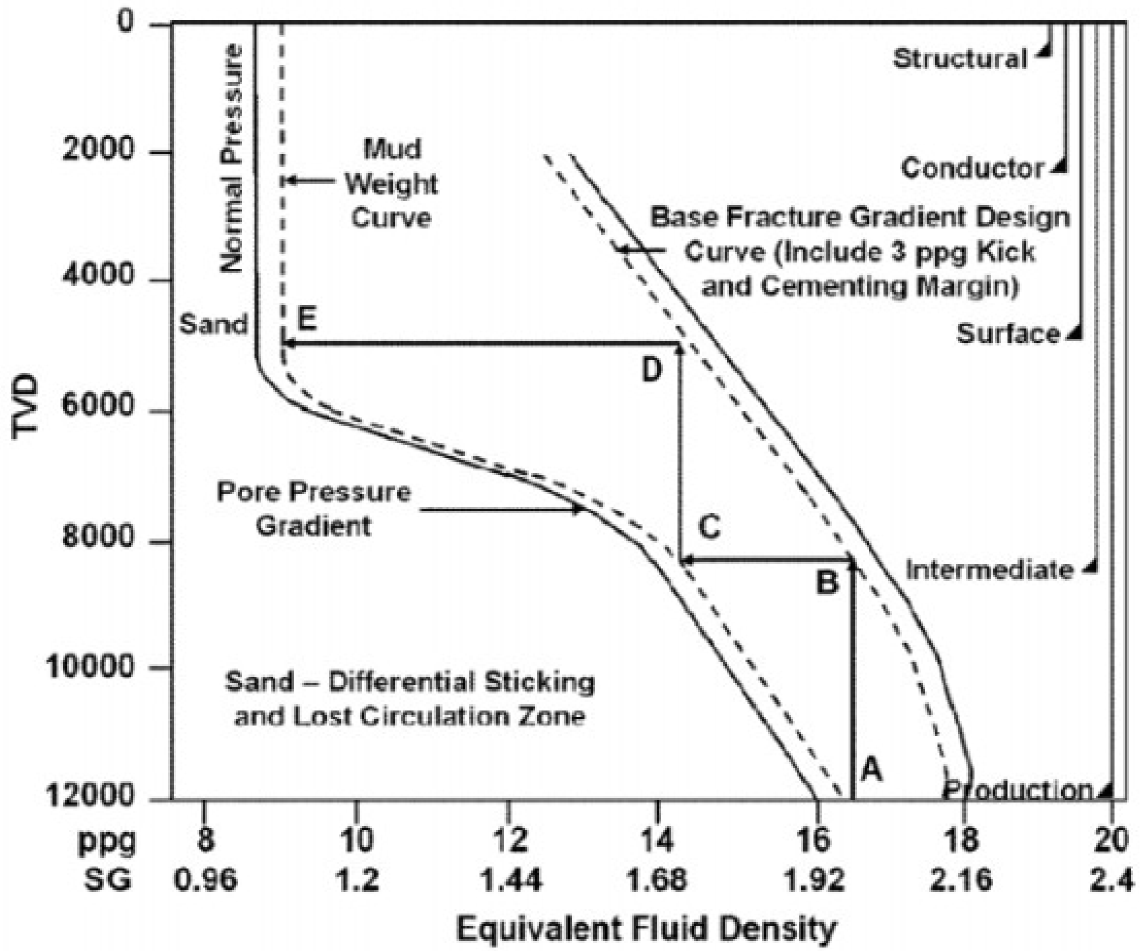

Figure 7.1. Casing Setting Depth Diagram