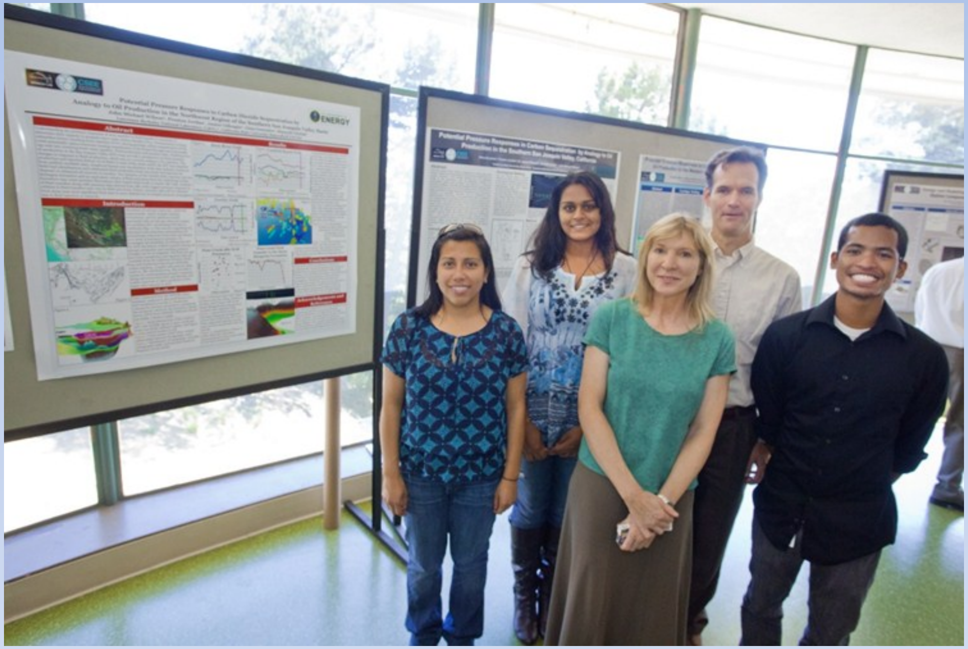
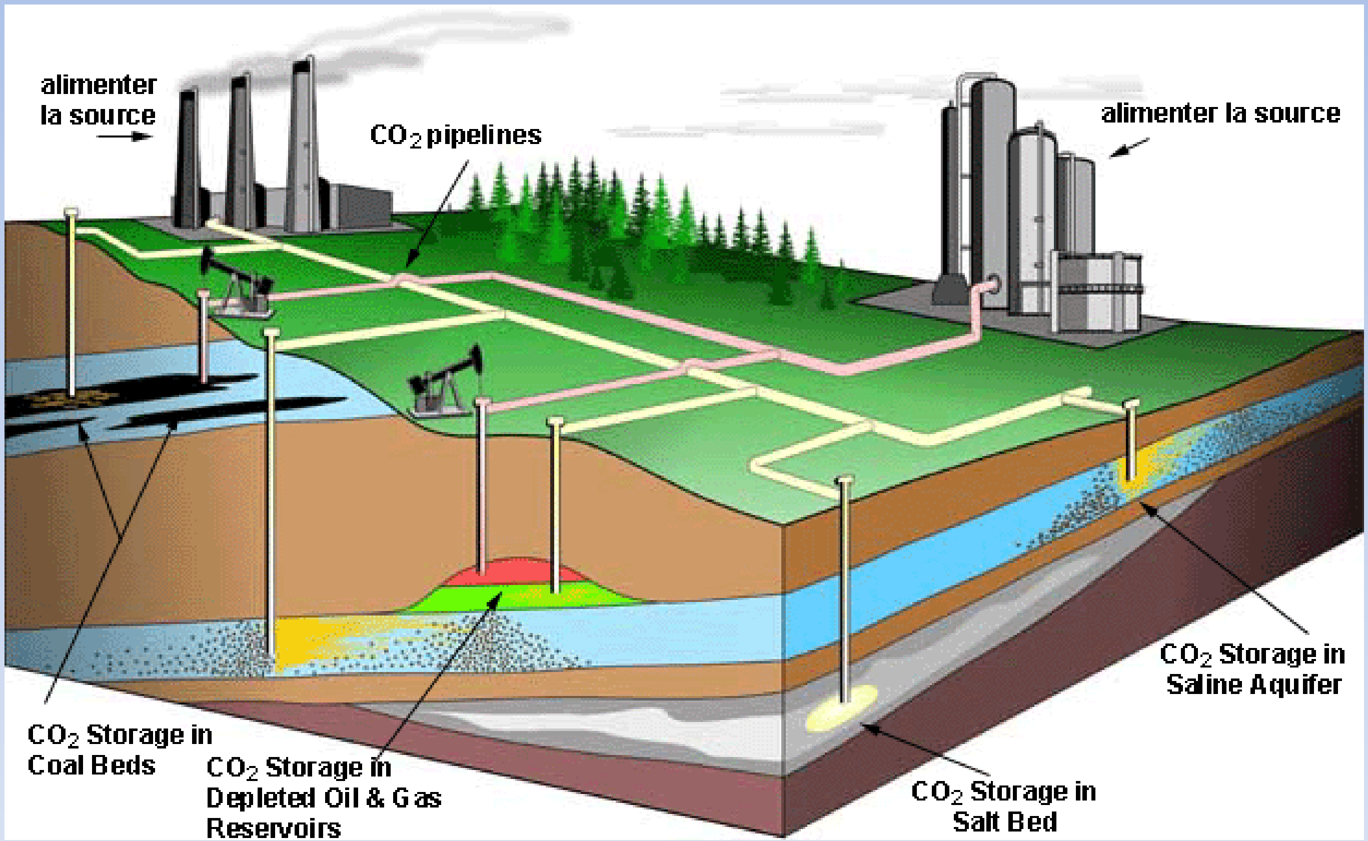
A qualitative assessment of storage capacity in depleted San Joaquin Valley oil reservoirs



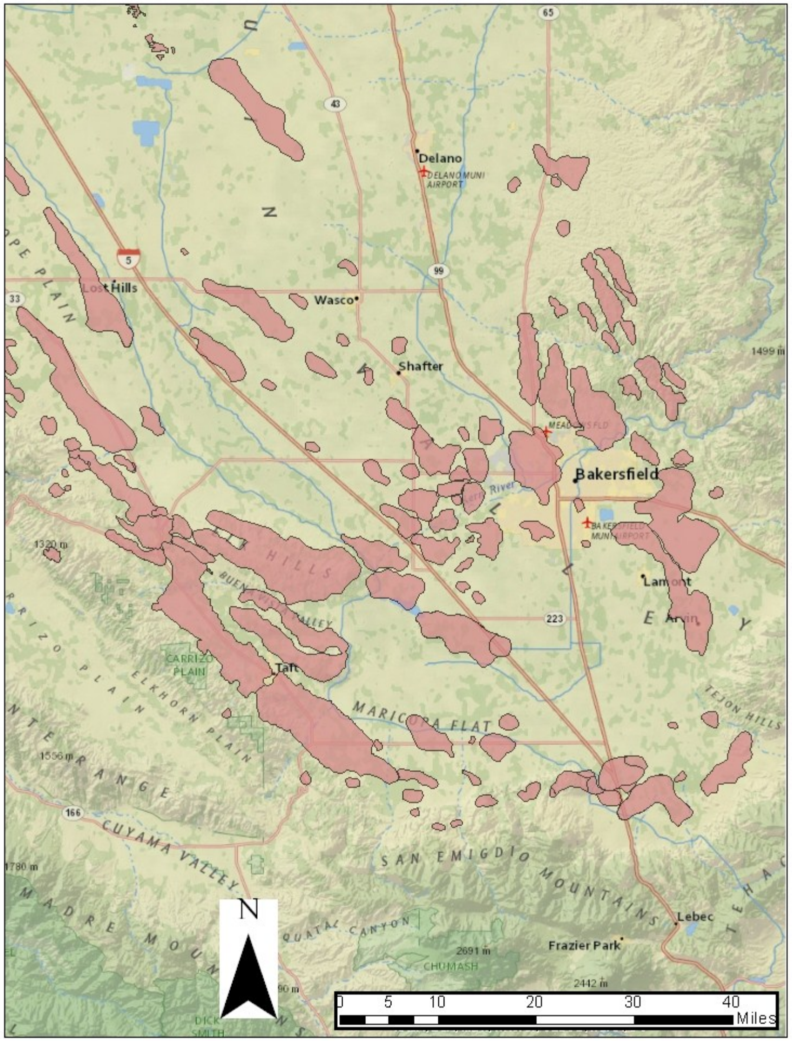
Jan Gillespie, Simarjit Chehal, Gina Gonzalez and John Wilson, CSU Bakersfield

Preston Jordan, Lawrence Berkeley National Lab

Target formations for CO_2 storage



San Joaquin Valley Oilfields



How much CO_2 can be stored in these fields?

- **How much net fluid has been produced from fields that meet standards for CO_2 storage?**
- **What is the response of reservoir pressure to this production?**

Data Sources for Initial Study

(Gillespie, 2011)

- WESTCARB GIS Database – California Oilfields and Power Plants
- California DOGGR – Cumulative oil production from each reservoir in each oilfield, oilfield water salinities, temperatures, average depths and formation volume factors.

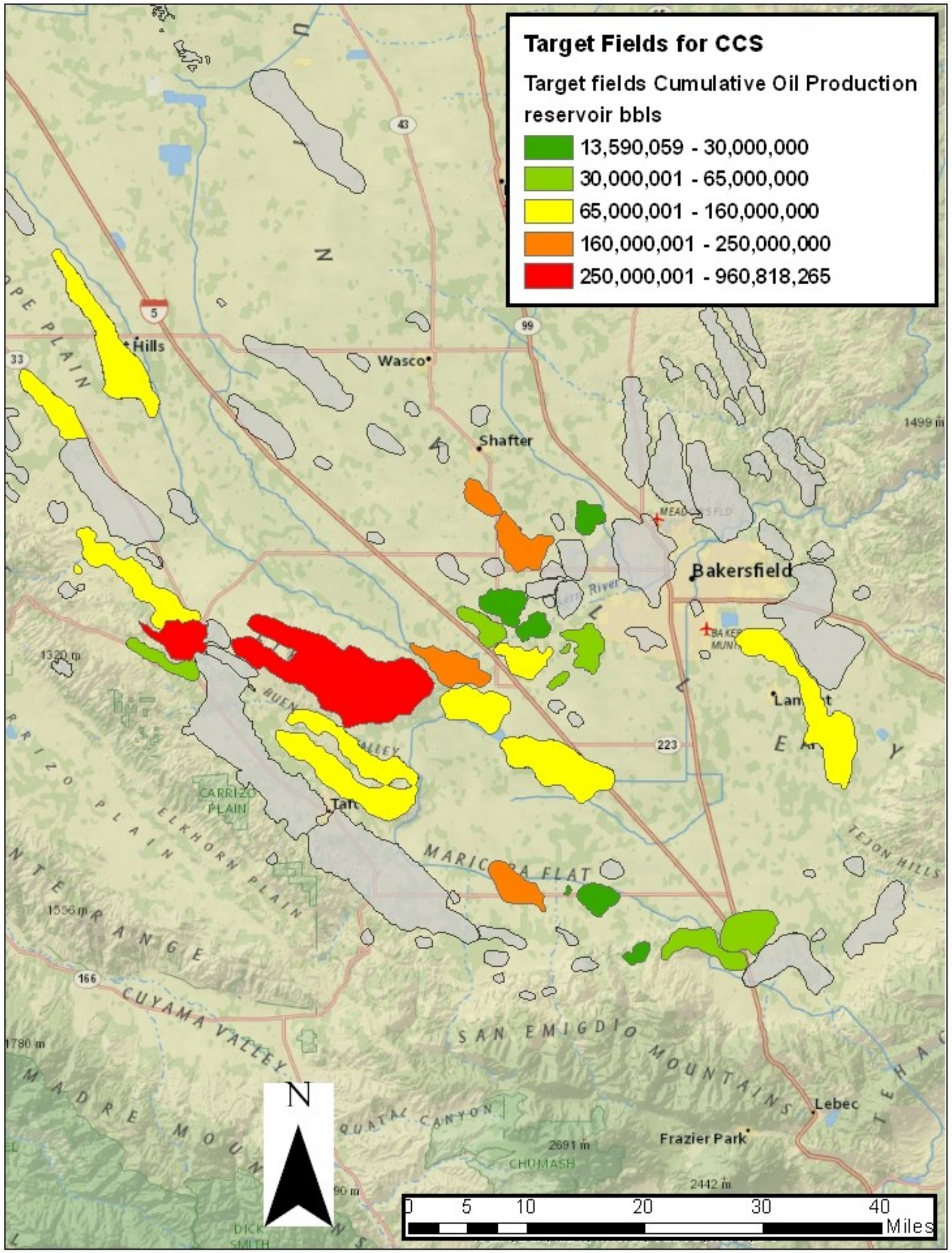
USGS criteria for carbon storage

- **3000 feet minimum depth**
- **Formation water salinity greater than 10,000 ppm Total Dissolved Solids (TDS) (based on US EPA guidelines)**
- **Minimum storage size 12.5 MM Bbls (equivalent to 1 to 1.4 MM metric tons of CO_2)**

Burruss et al., 2009

Cumulative production calculations—initial study

- Used only oil production (DOGGR 2007)—did not consider produced or injected water or gas.
- Corrected volume of produced oil for shrinkage using formation volume factors from DOGGR reports to convert produced oil from surface barrels (Stock Tank Barrels) to reservoir barrels



--Twenty five fields met the USGS criteria.

Gillespie, 2011

Data for New Study

- The new study uses production and injection data for oil, water and gas obtained from DOGGR
- It also considers changes in pressure in the reservoirs through time (using the pressure gradient factor “w”) to determine how the reservoirs respond to fluid injection and removal.
- Initial pressure data is from DOGGR (1998) and later pressure data from DOGGR idle well fluid levels.

What we are trying to determine

- Initial conditions
- Boundary conditions—open or closed container
- Heterogeneity
- Structure

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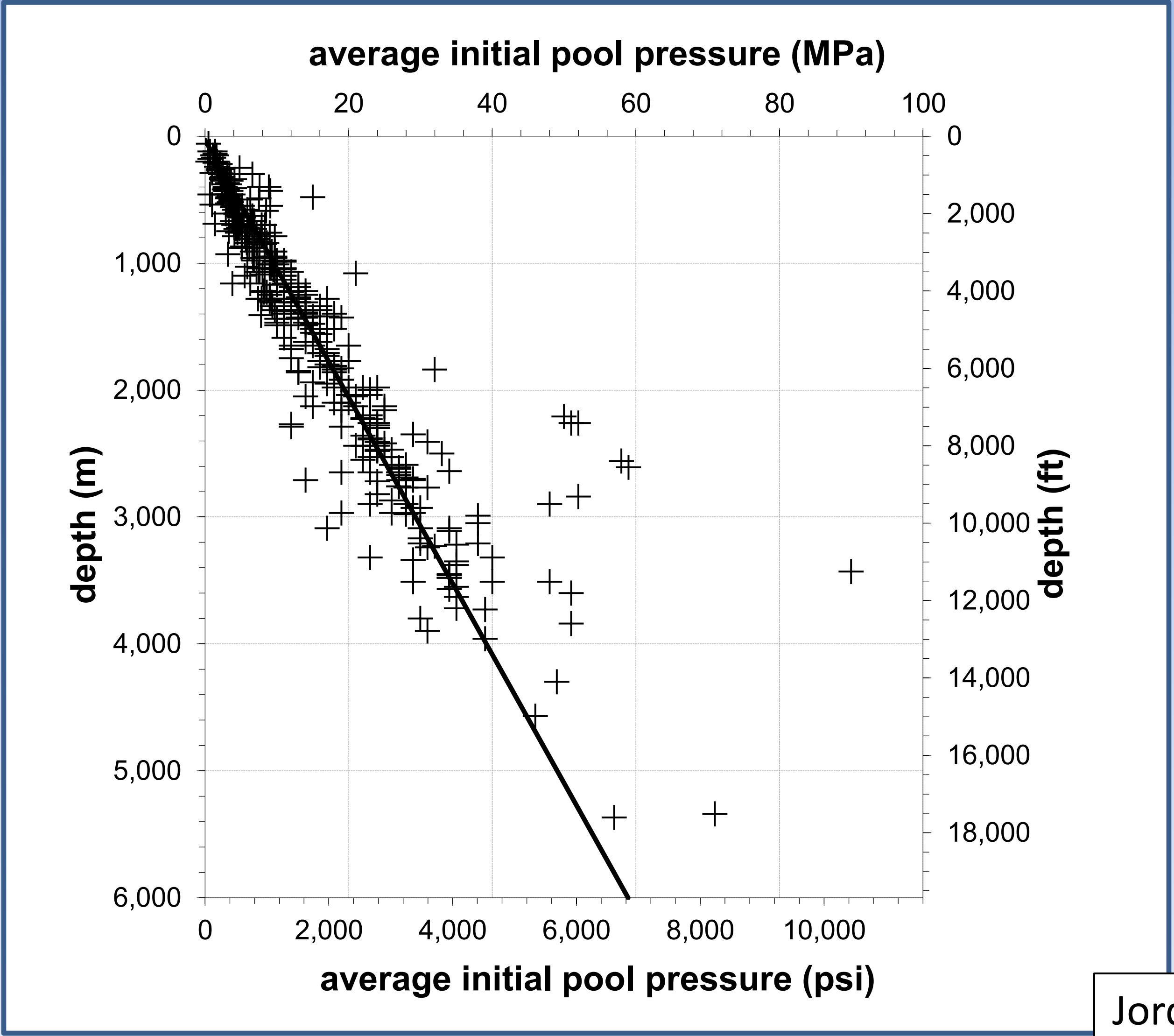
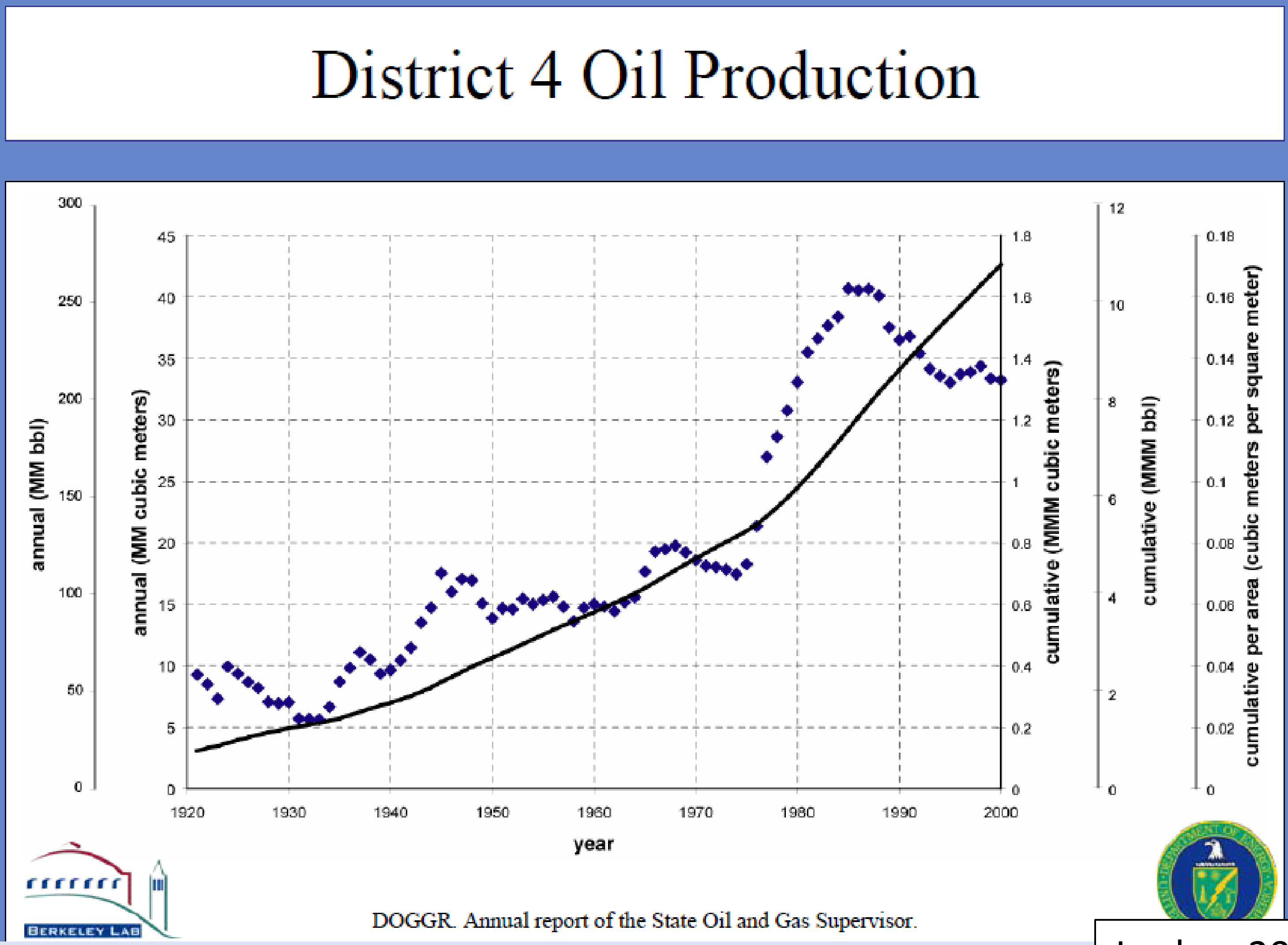
Initial discovery pressure of SJV oilfields



Jordan, 2010

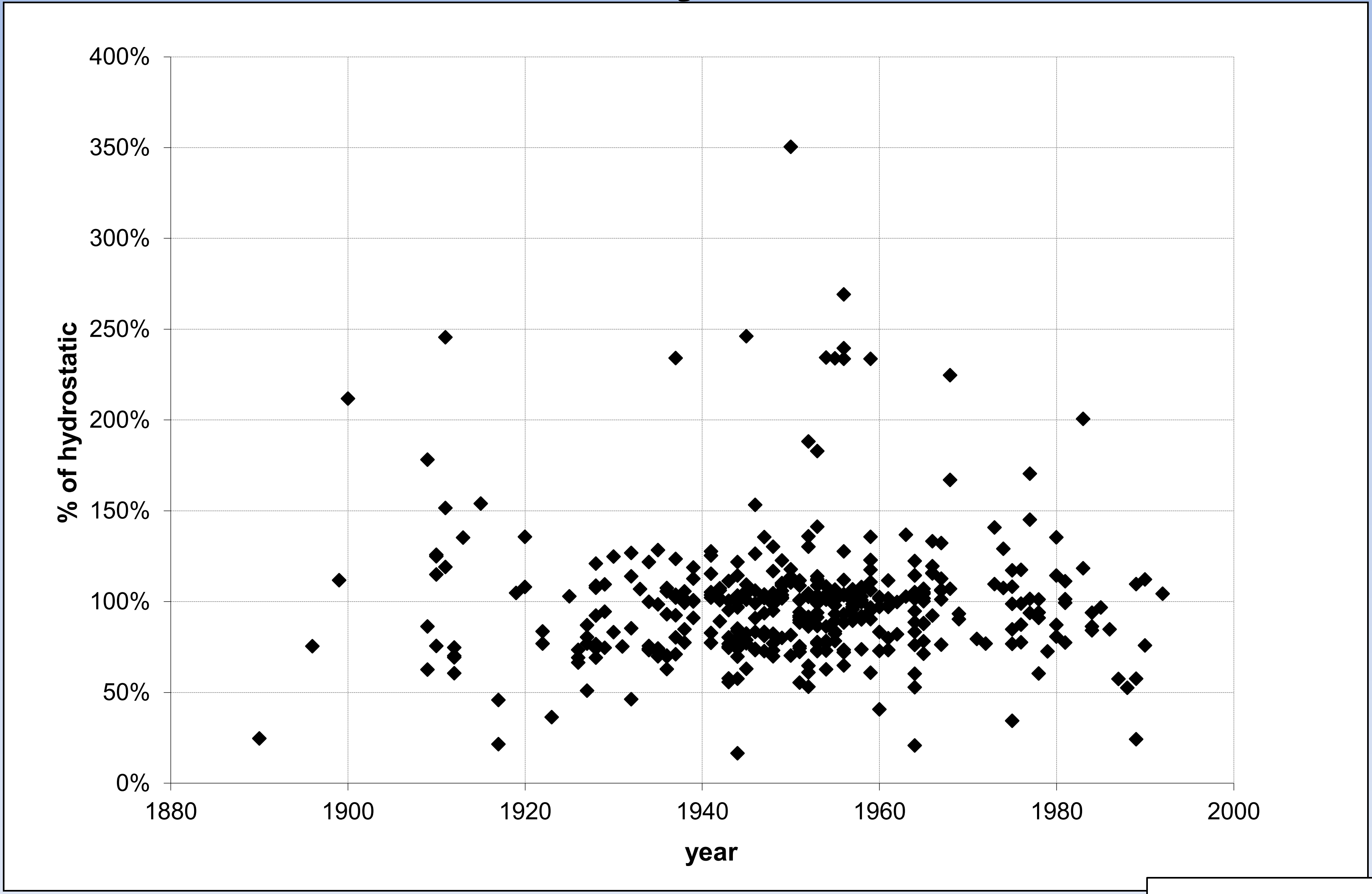
Cumulative oil production in SJV



DOGGR. Annual report of the State Oil and Gas Supervisor.

Jordan, 2010

Initial discovery pressures over time as % of hydrostatic



Jordan, 2010

Normalizing the pressure

$$w = \frac{g}{h} - 1 \qquad \text{for} \qquad g > h$$

$$w = 0 \qquad \text{for} \qquad g = h$$

$$w = -\frac{h}{g} + 1 \qquad \text{for} \qquad g < h$$

where g is the measured pressure converted to a gradient by dividing by depth and h is the hydrostatic gradient

Jordan, 2010

Normalizing the pressure

$$w = \frac{g}{h} - 1 \qquad \text{for} \qquad g > h$$

$$w = 0 \qquad \text{for} \qquad g = h$$

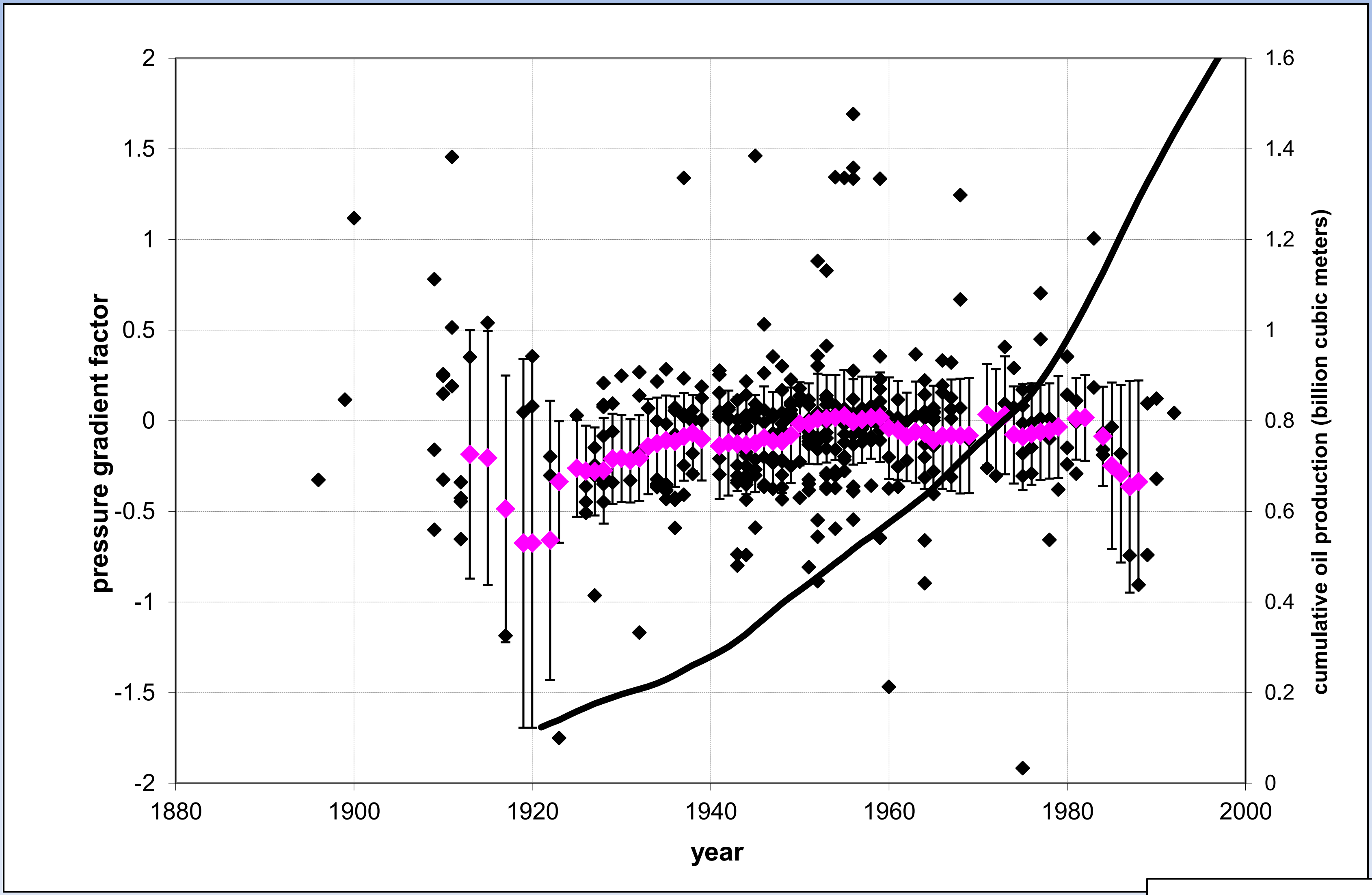
$$w = -\frac{h}{g} + 1 \qquad \text{for} \qquad g < h$$

If w >0, field is over-pressured

If w <0, field is under-pressured

Jordan, 2010

Initial pressure relative to fluid withdrawal



Jordan, 2010

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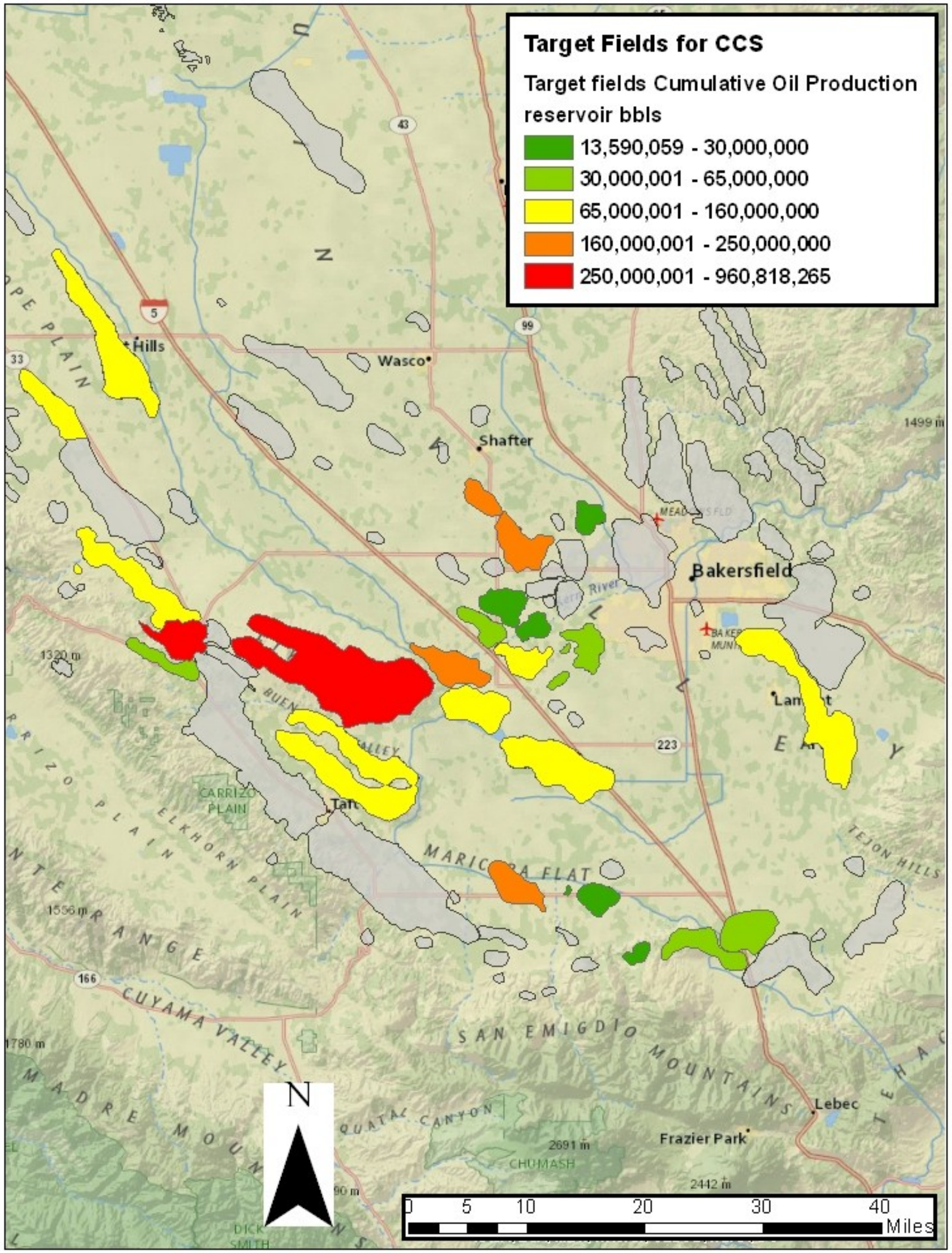


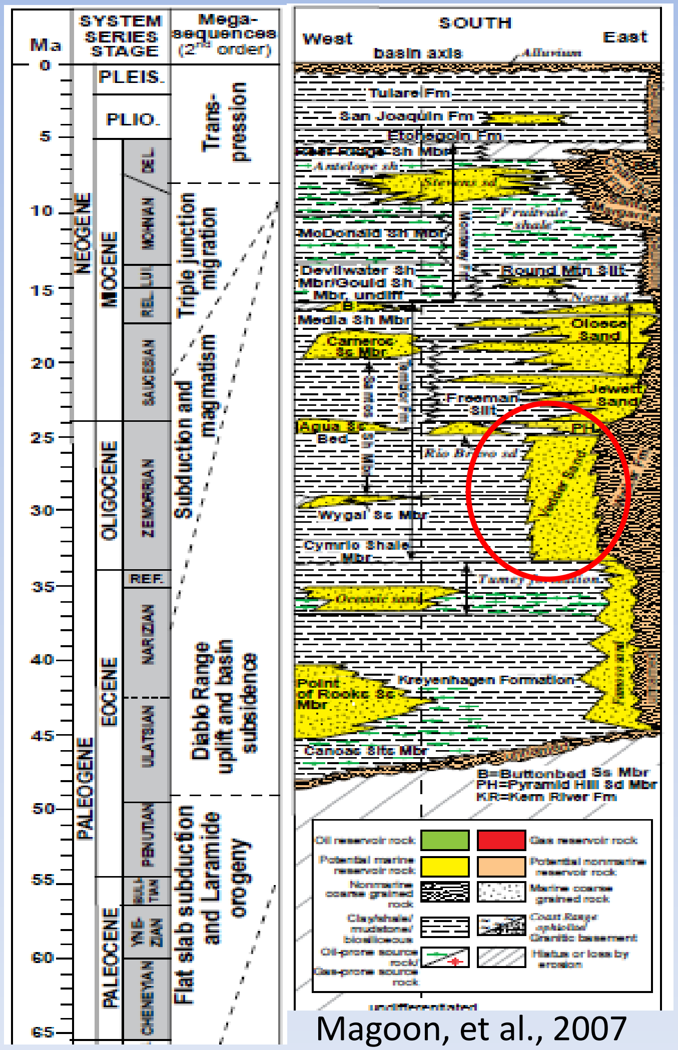
--Twenty five fields met the USGS criteria.

--The majority of the production comes from three reservoirs:

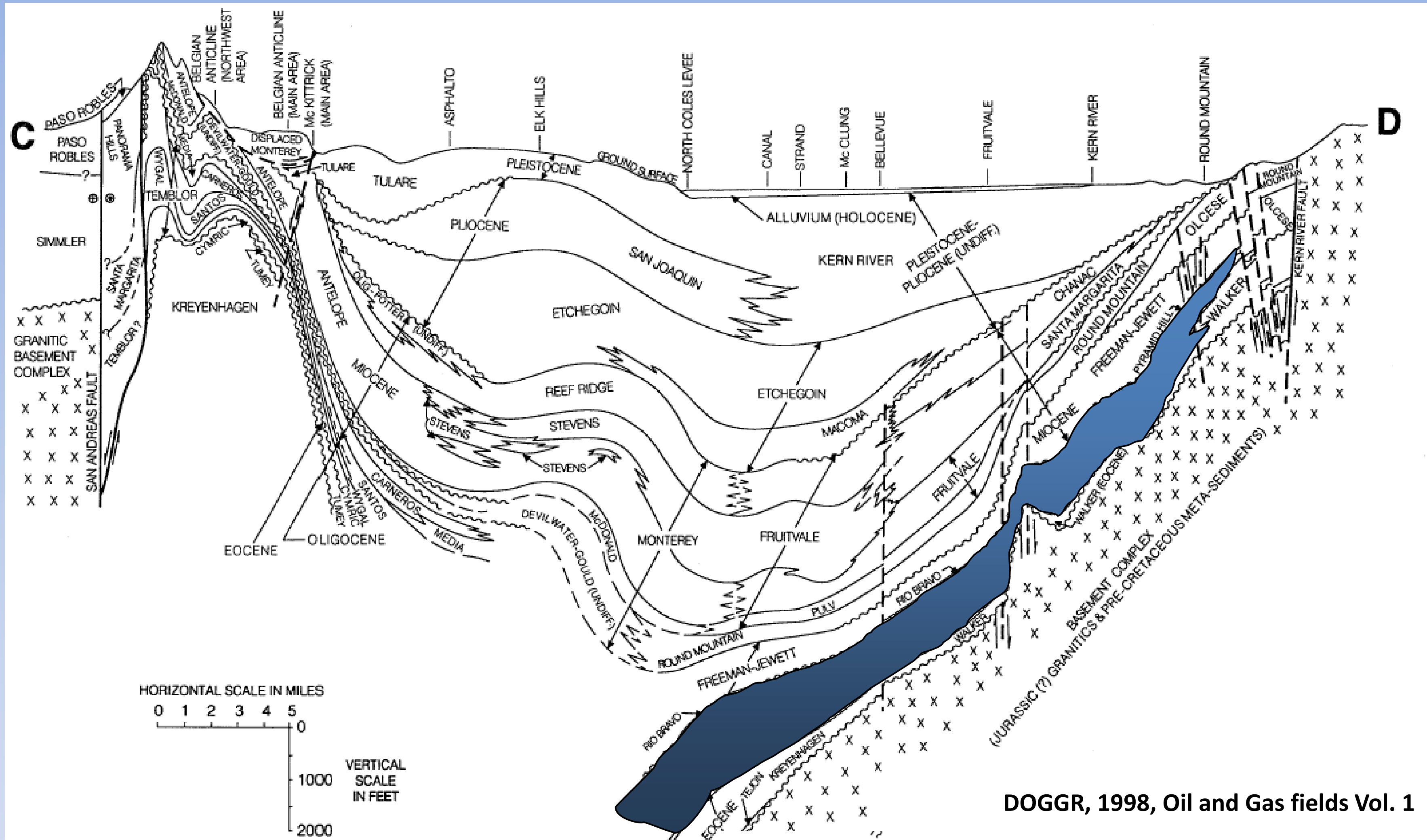
1) **Vedder Formation**
2) **Temblor Formation**
3) **Stevens Sandstone (Monterey Formation)**

Gillespie, 2011

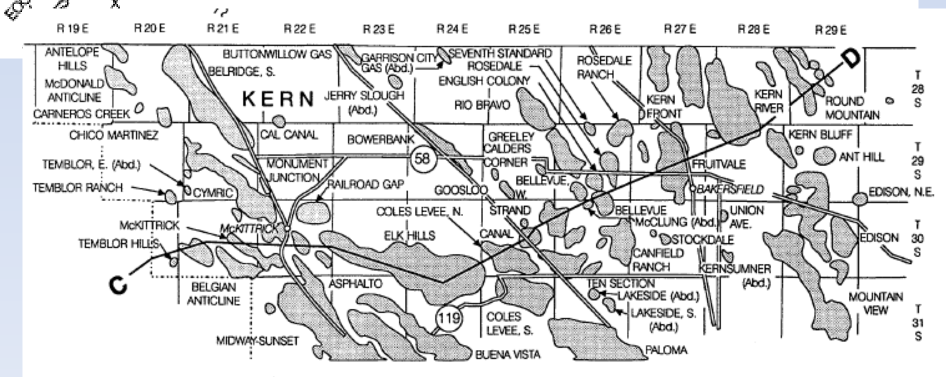
The Vedder Formation



Magoon, et al., 2007

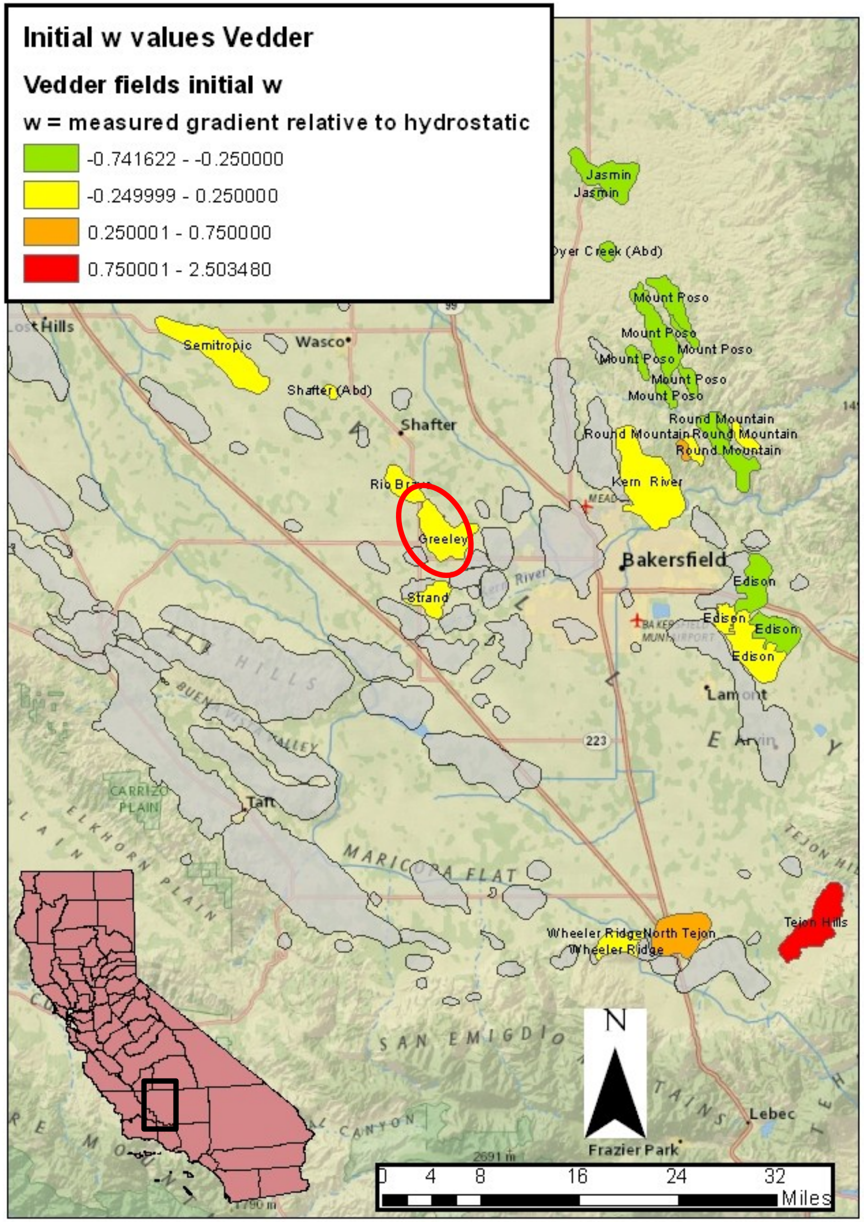


DOGGR, 1998, Oil and Gas fields Vol. 1



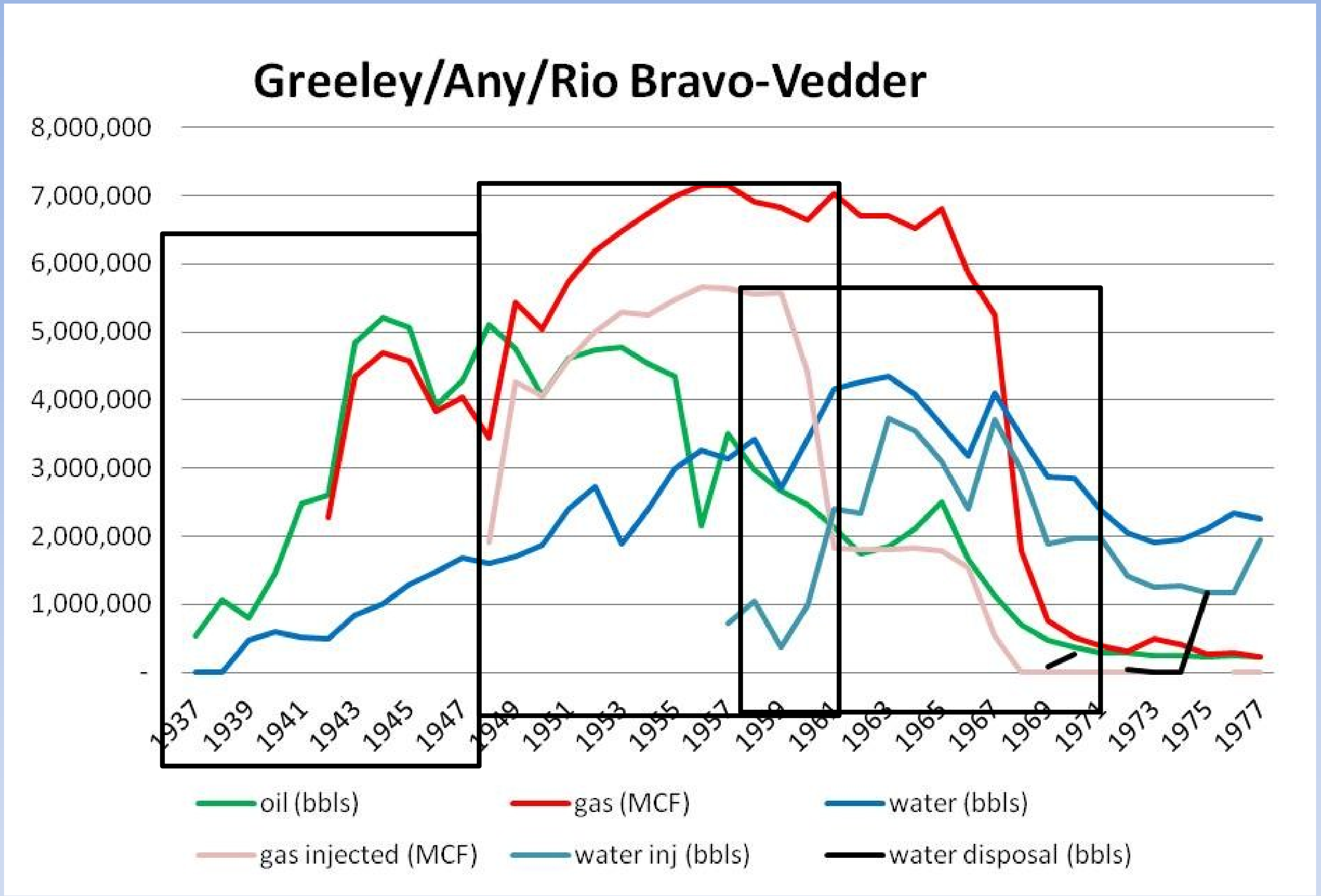
Vedder Fm.

~400,000,000 Reservoir bbls in the target fields

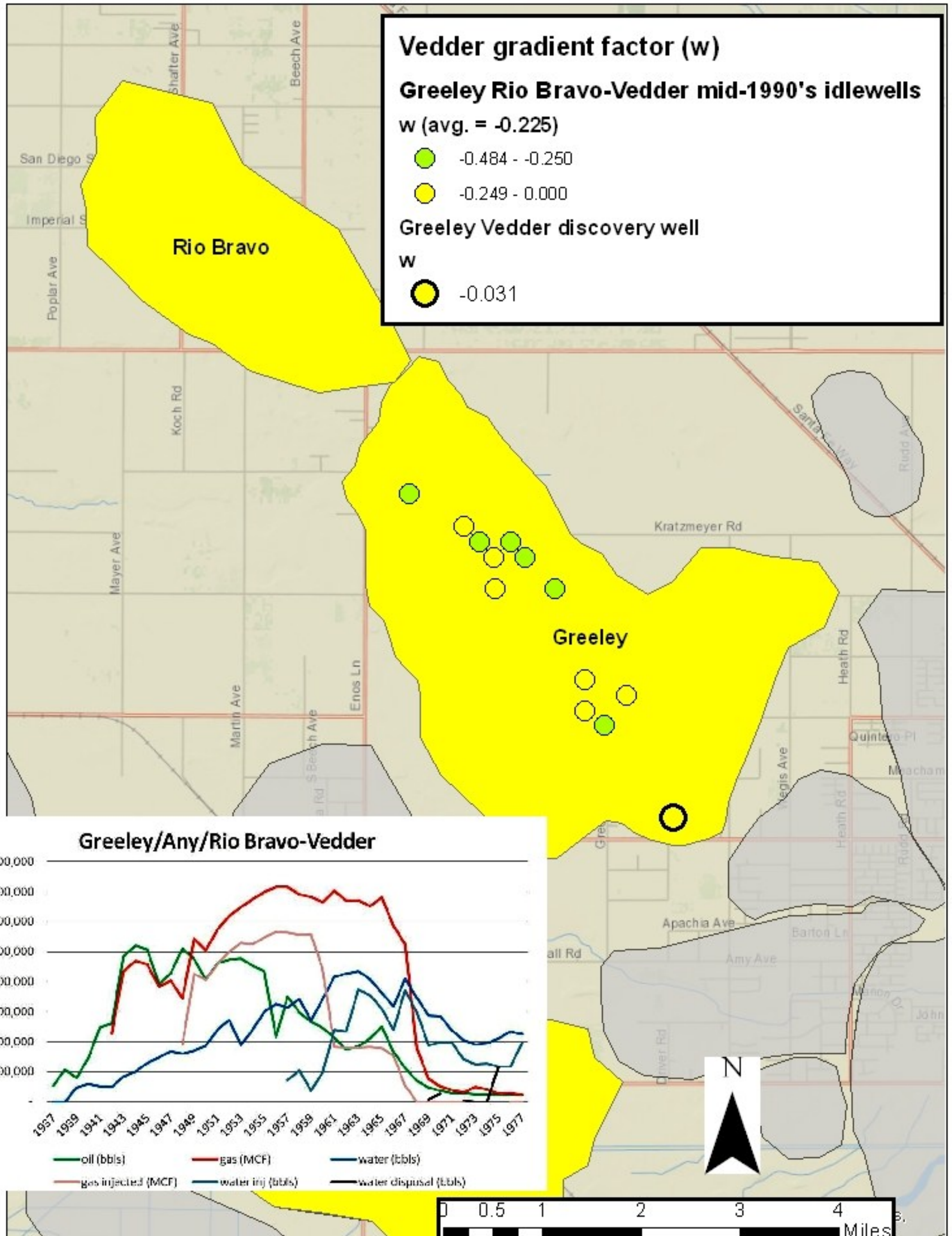


--Fields near the basin axis have pressures near hydrostatic. Fields on the eastern basin margin tend to have pressure gradients lower than hydrostatic

--the high pressure gradient at Tejon Hills field to the south appears to be due to erroneous pressure data in the CA DOGGR Oil & Gas volume. Formations above and below the Vedder have initial pressures ranging from 200-750 psi, the Vedder shows an initial pressure of 2,230 psi.



- Strong water drive (water cut rapidly increases and 894 scf/bbl initial solution gas/oil ratio about matches initial production ratio)
- Pressure maintained by re-injection of produced gas 1948 - 1967
- Blow down gas cap and waterflood by re-injection of produced water 1952 - 1983.

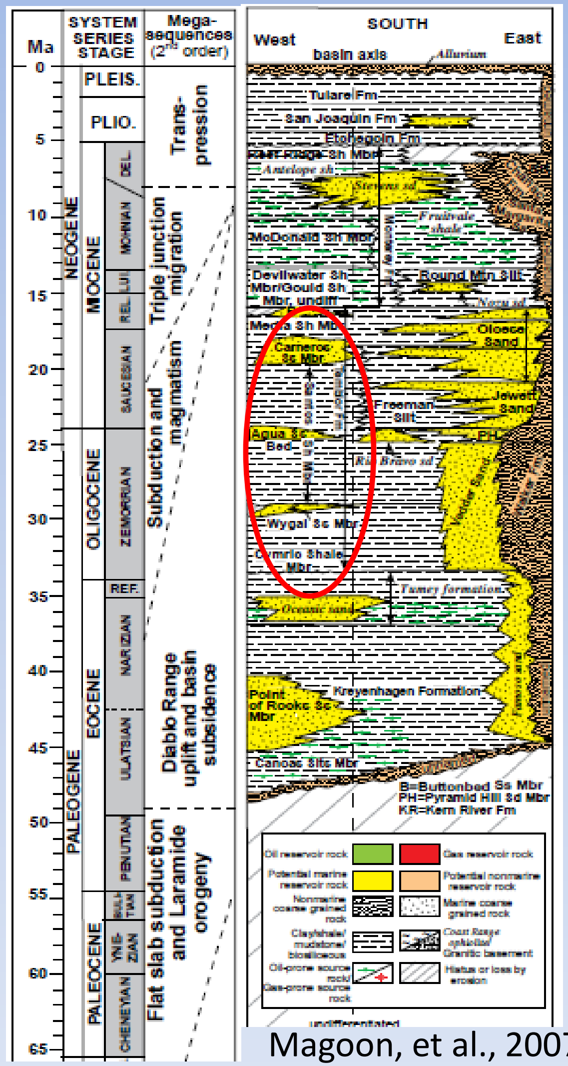


--Pressure gradient dropped very little from 1938-mid 1990's

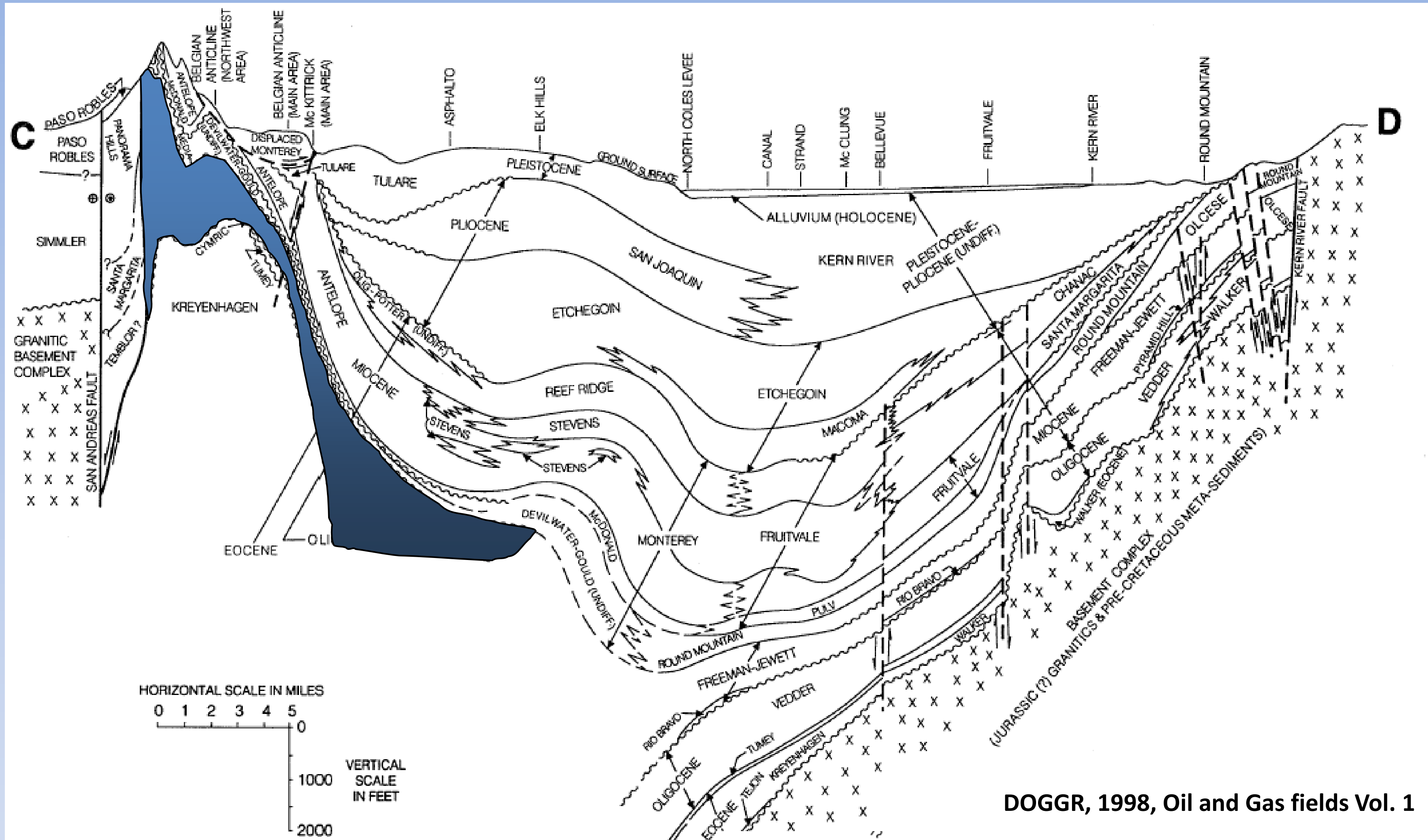
--Despite the fact that water injection was discontinued in 1983, average w value has decreased by only 0.19 over 50 years (0.004/yr)

--This suggests that pressures are being maintained by an active natural water drive.

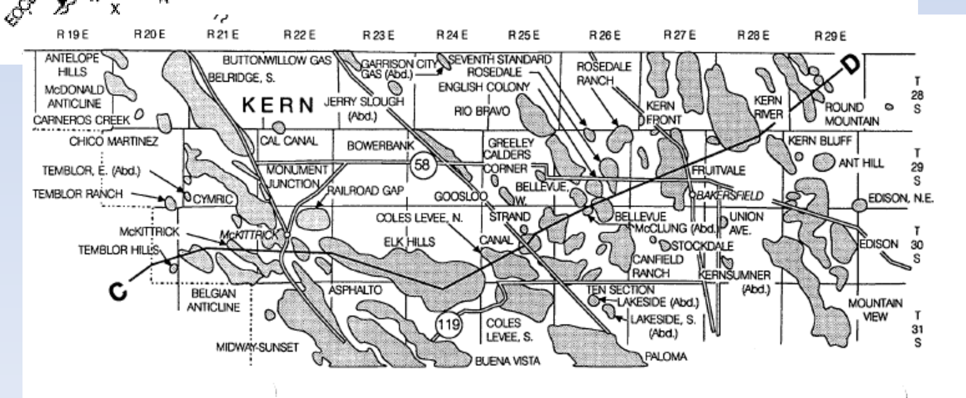
The Temblor Formation



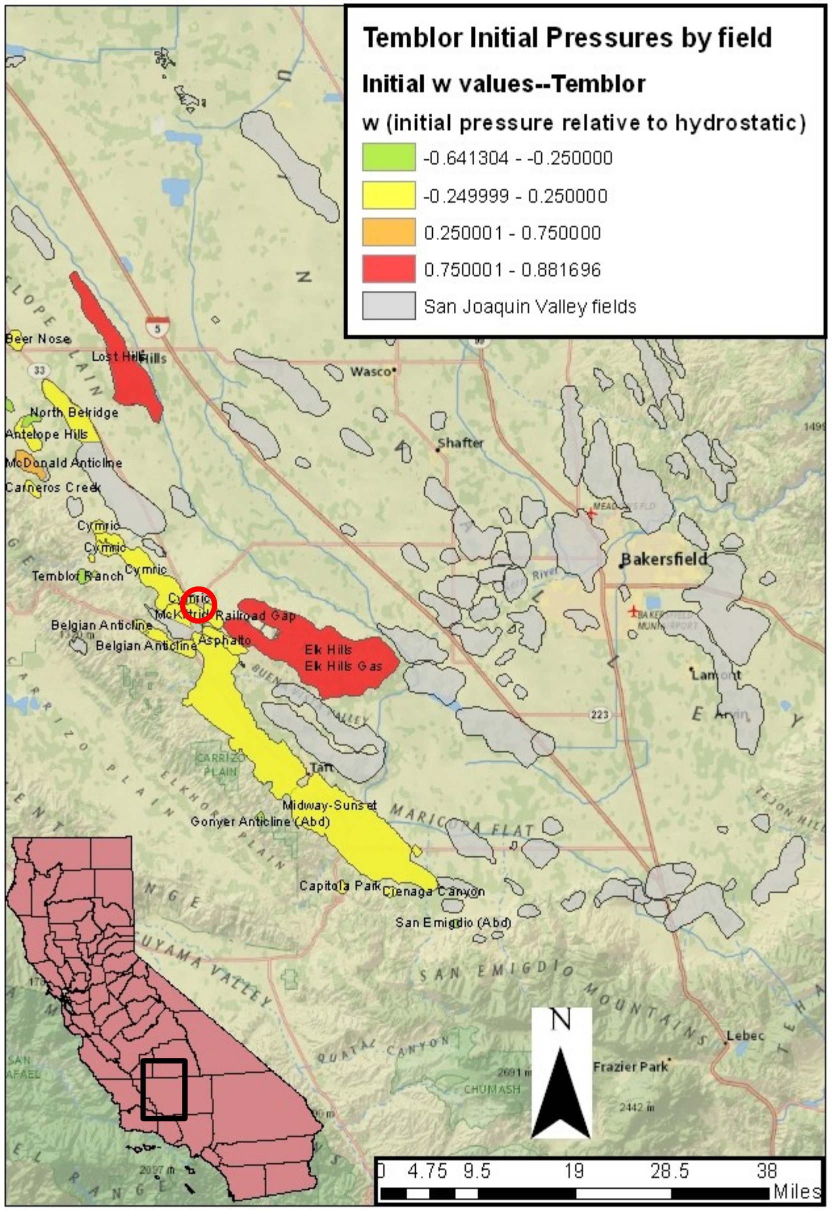
Magoon, et al., 2007



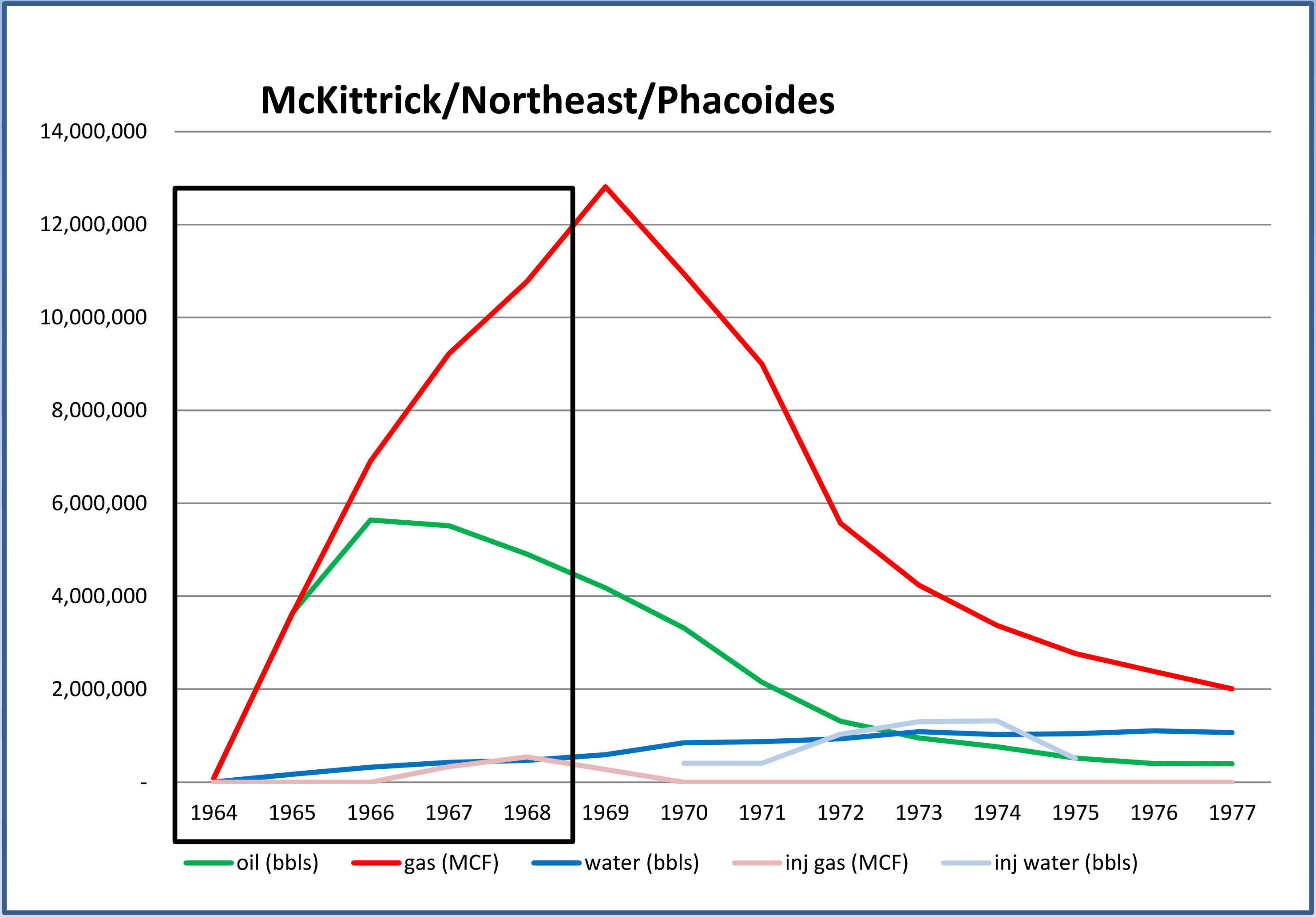
DOGGR, 1998, Oil and Gas fields Vol. 1



Temblor Fm.
~500,000,000 Reservoir bbls in the target fields

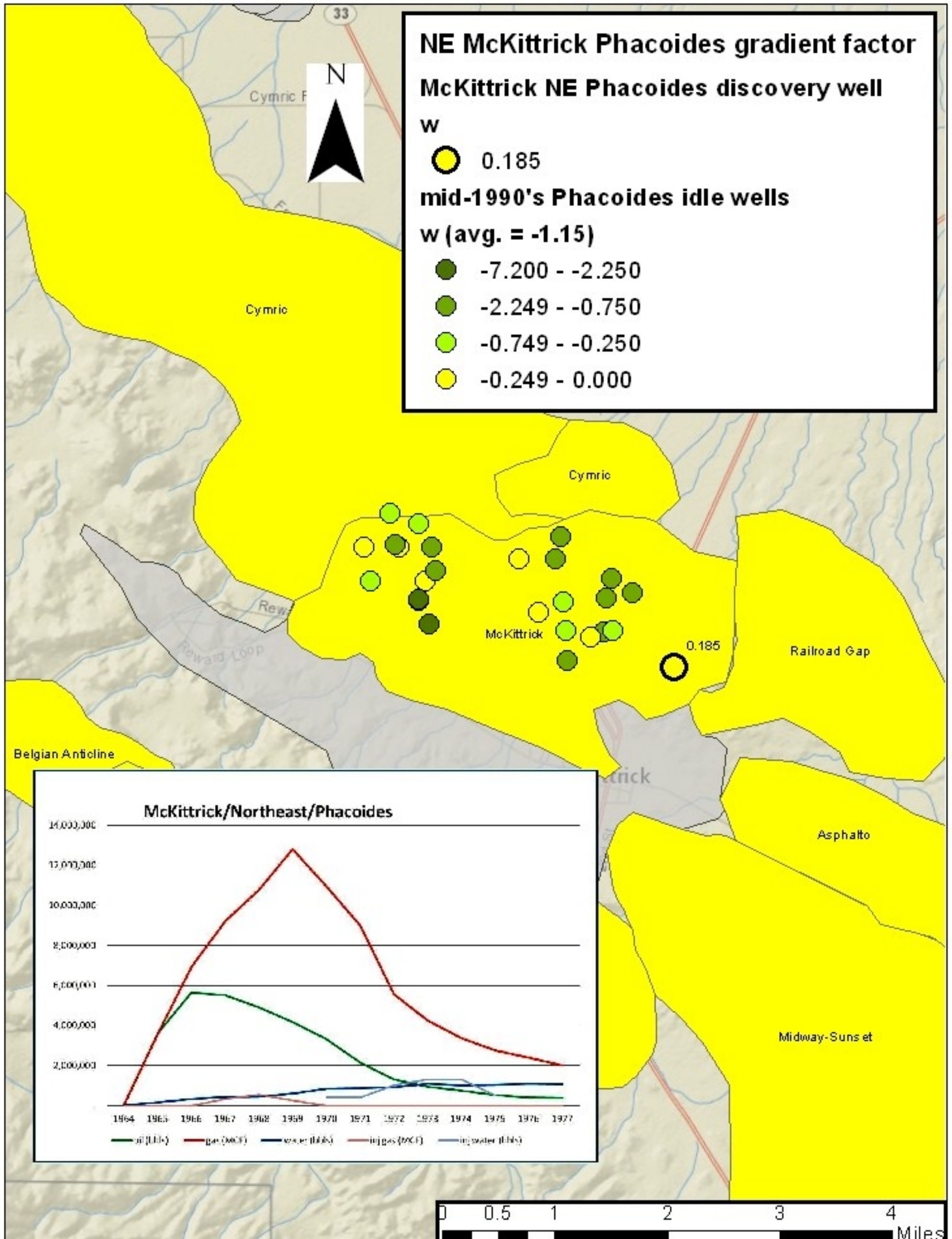


--Pressure gradient factors are generally higher than hydrostatic near the basin axis. Fields on the western margin of the basin tend to be hydrostatic or slightly under-pressured.



- **The Phacoides reservoir at Northeast McKittrick appears to be a gas expansion drive reservoir (production ratio quickly surpasses 750 scf/bbl initial solution gas to oil ratio and small water cut maintained).**

- **Very little injection has occurred in this reservoir in order to maintain the pressure.**



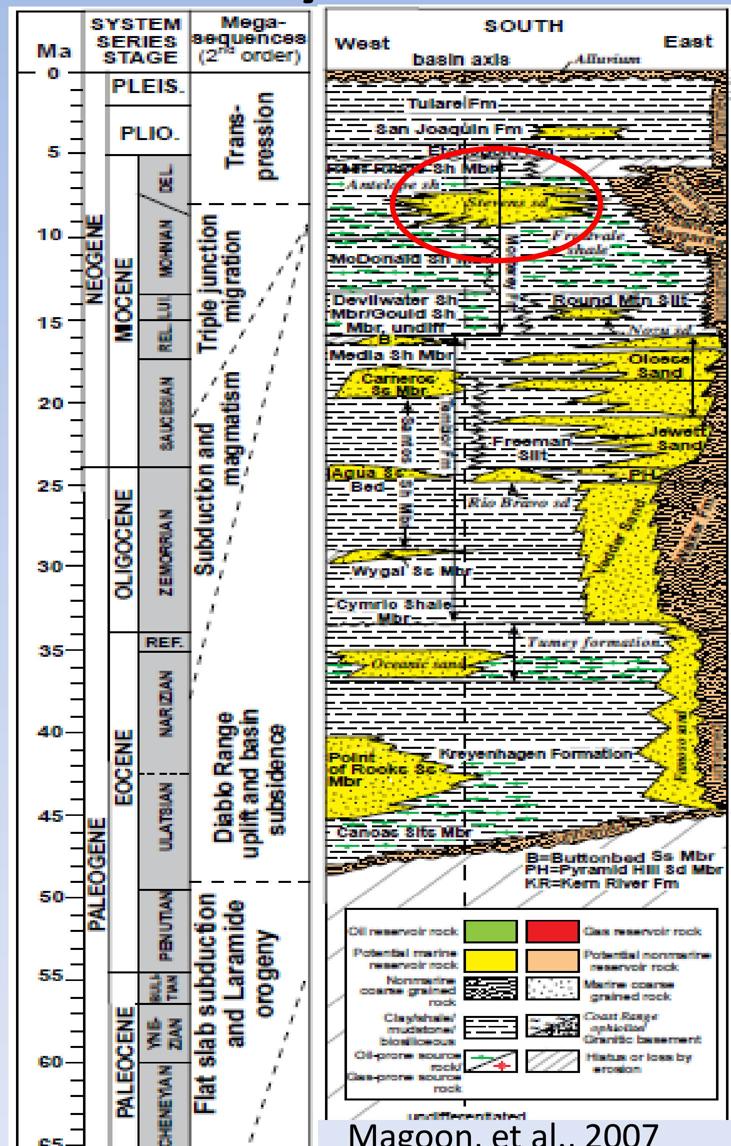
--Pressure gradients have decreased significantly from discovery in 1964 to the mid-1990's.

--The average w value has decreased by 1.335 over a period of 30 years-- a rate of 0.045/yr.

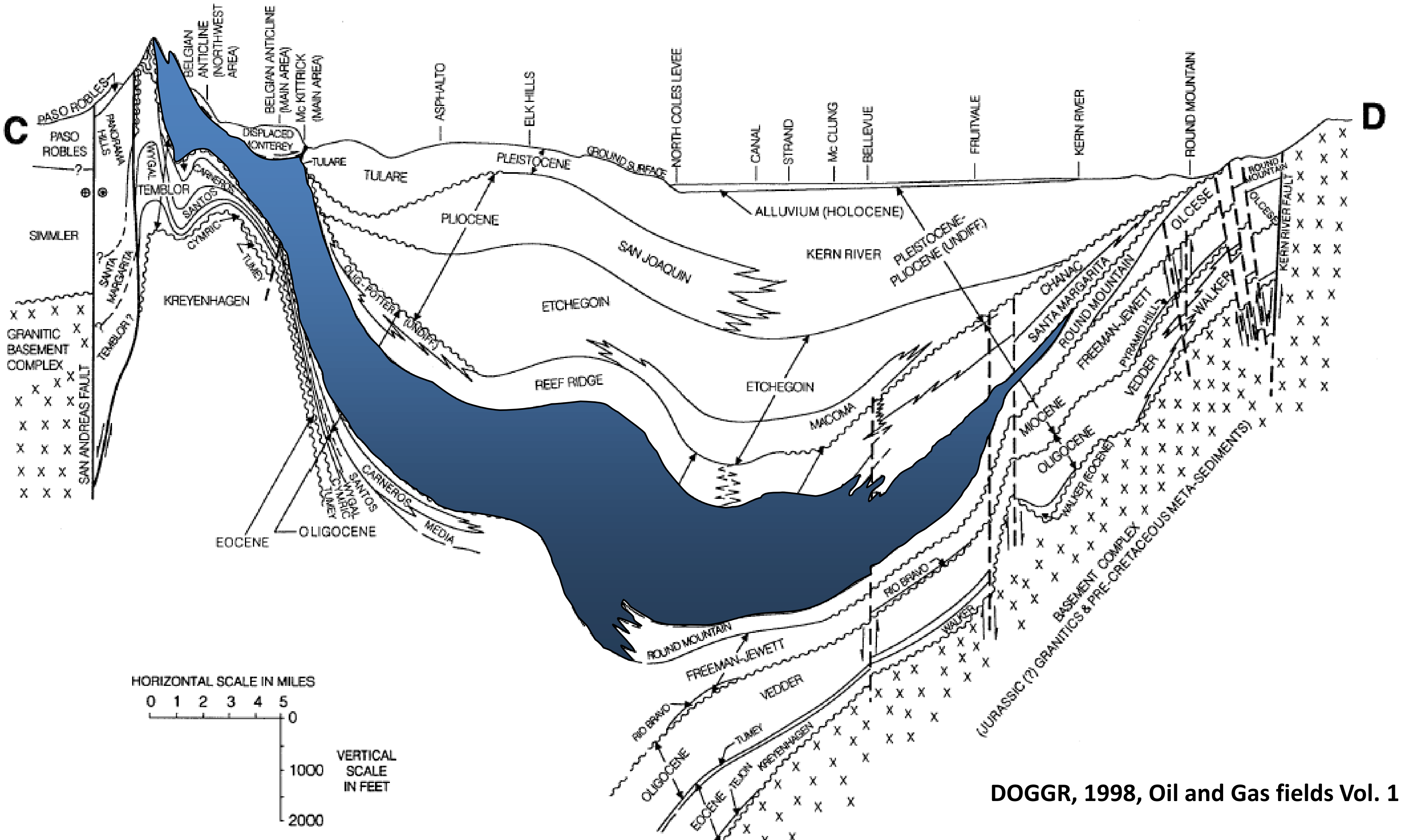
--This suggests an isolated reservoir with a solution gas or small gas cap drive. It is not connected to a strong aquifer.

--The variability in the idle well w values suggests a compartmentalized reservoir

The Stevens Sandstone (Monterey Formation)

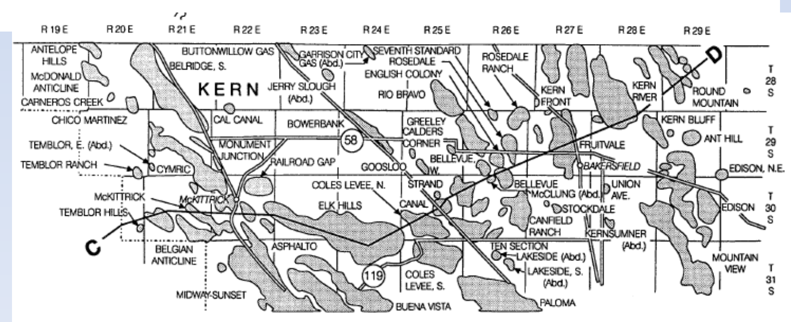


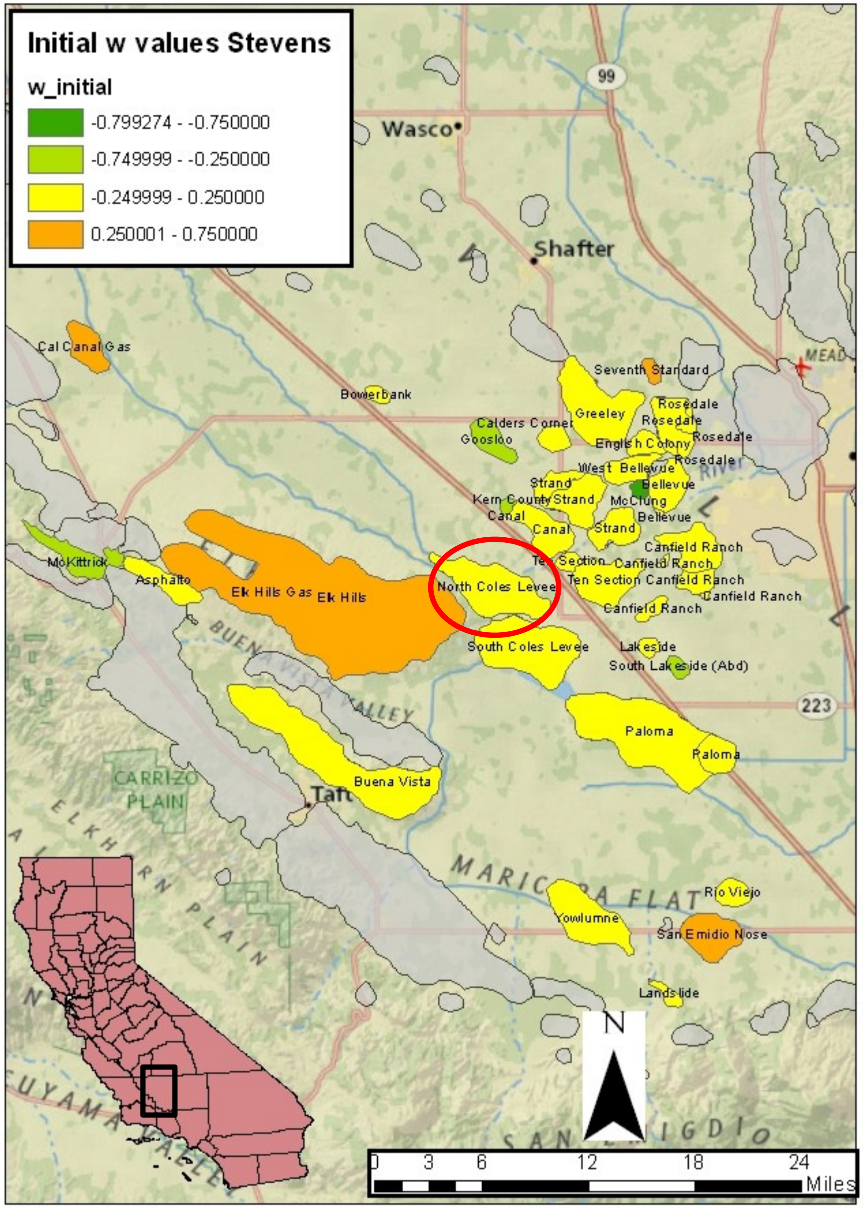
Magoon, et al., 2007



DOGGR, 1998, Oil and Gas fields Vol. 1

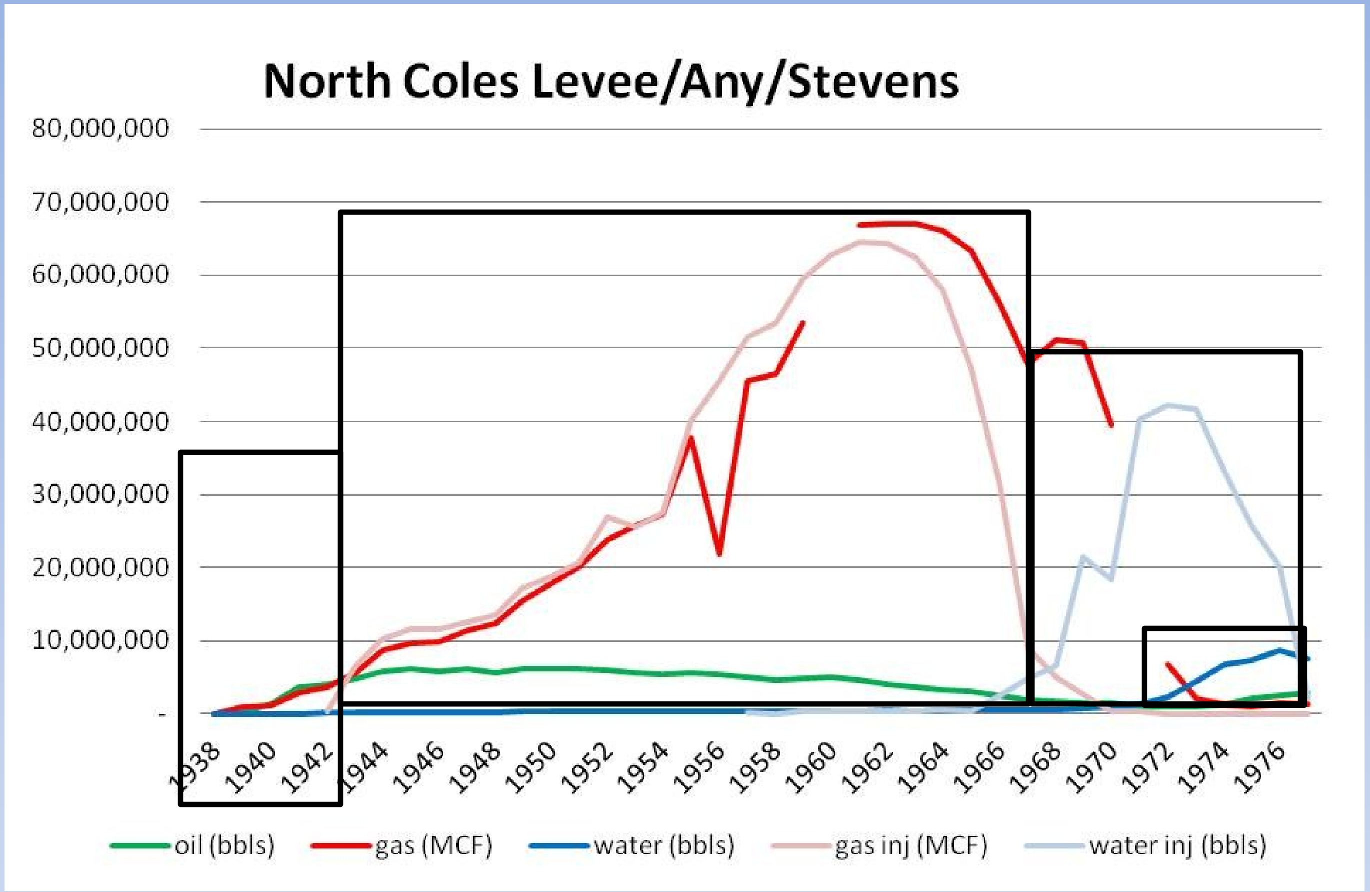
Monterey Fm. (primarily Stevens Sand)
~2,000,000,000 Reservoir bbls
in the target fields



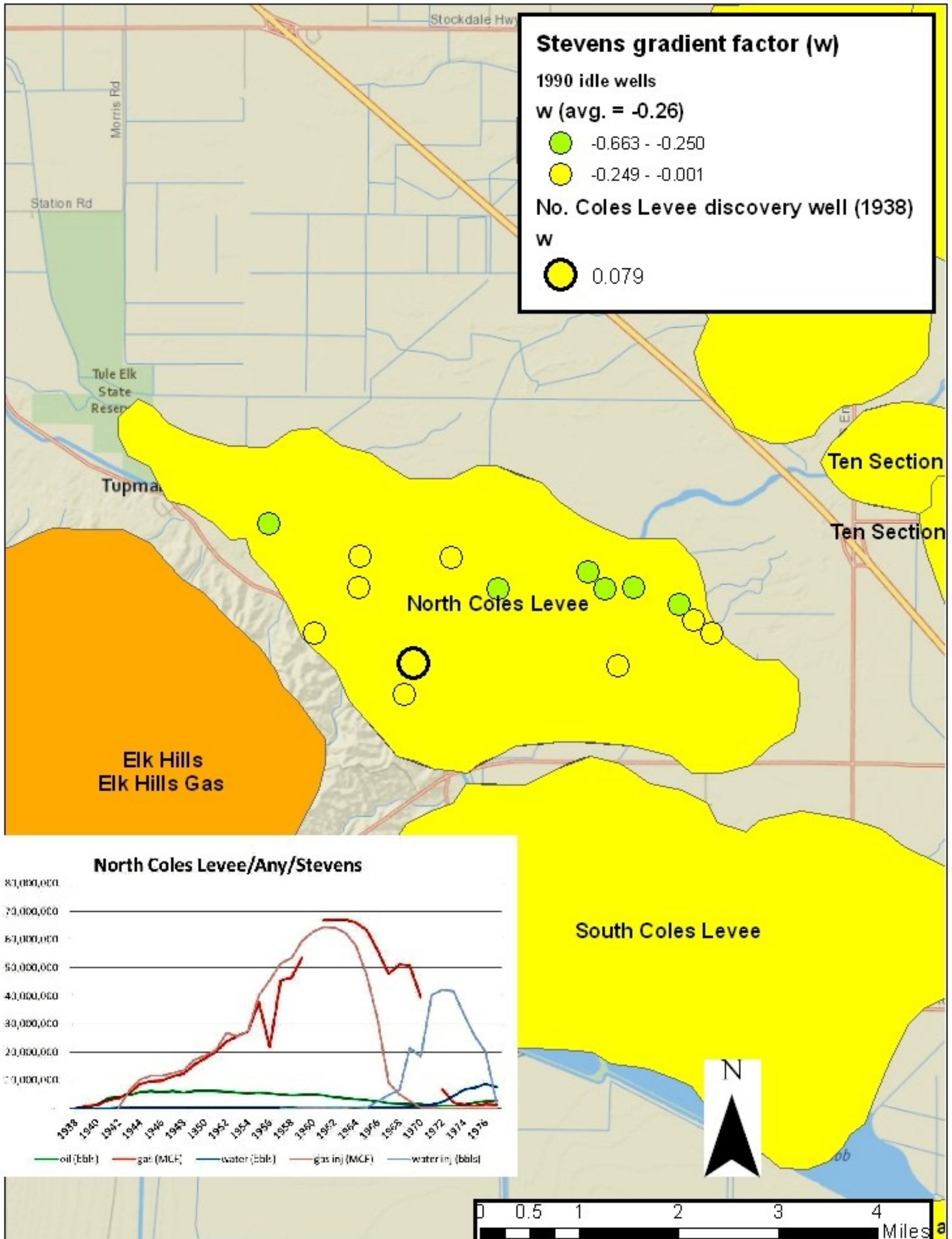


--Stevens pressure gradient factors are highest in the basin axis where they are slightly over-pressured relative to hydrostatic.

--Stevens pressures along the basin margins and along the axis of the Bakersfield Arch are close to hydrostatic.



- **North Coles Levee gas expansion drive initially (600 initial solution gas to oil ratio about matches initial production, and almost no water cut).**
- **Gas drive was maintained by the reinjection of produced gas early in its life (1942-1969).**
- **Water injection commenced in 1964 and is currently active. The amount of water injected is much greater than the amount of water produced. The injected water comes from a different reservoir.**
- **The increase in water production shown in 1972 probably represents the breakthrough of this injected water rather than a significant water drive effect.**



--W values start out near hydrostatic and decrease only 0.34 over 52 years (a rate of 0.007/yr).

--This is probably due to the strong gas cap drive and careful early maintenance of the gas cap.

--In addition, the water injection program is still active and the injected volume includes both re-injected produced water and water from other reservoirs. This creates the effect of an artificial water drive in a reservoir without a significant natural water drive.

Conclusions

- The type of natural drive system in the reservoir will affect the amount of CO_2 that can ultimately be stored
- A strong water drive, such as that in the Vedder Fm. at Greeley, is favorable for storing amounts of CO_2 greater than the previously produced volume (open system limits pressure increase)
- Discounting pore collapse and assuming injection only (no brine extraction), a weak water drive is better for storage up to the previously produced volume (probably underpressured)
- This is particularly true in reservoirs with past gas injection pressure maintenance followed by blowdown (almost certainly underpressured)

Future directions

- Use the new database (after we fill in the data gaps) to correlate net fluid extraction to w values to see how different reservoirs react to fluid volume changes.
- Ongoing detailed mapping, production and pressure studies to try to determine the degree of compartmentalization of the reservoirs in some of the target fields.

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