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## **The Impact of Carbon Geological Sequestration**

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### **Abstract**

Although CO<sub>2</sub> geological sequestration is the most popular carbon storage method promoted and pilot tested, the economic feasibility and technical risks for commercial scale sequestration projects are rarely mentioned. More significant is that, apart from rhetorical pronouncements, the would-be impact of the operation on climate change is not discussed. This work studies the technical risks, regulatory issues, and economic burden of CO<sub>2</sub> geological sequestration on the U.S. by using the Kyoto Protocol emission requirement as the base line. The potential effect of burying all the extra CO<sub>2</sub> regulated by Kyoto Protocol on global temperature change is also evaluated.

The lack of regulatory framework is blamed as one of the obstacles for slowing or stopping CO<sub>2</sub> geological sequestration practice. However, any regulatory issues are intertwined and dominated by the physics of the injection process itself and its economic viability. This study analyzes the uncertainty and/or risks caused by CO<sub>2</sub> geological sequestration in oil and gas reservoirs, saline aquifers, and coalbeds. The work shows that the potential technical and legal risks and financial costs for sequestering CO<sub>2</sub> underground make it impossible to promulgate any regulatory framework without causing detrimental effects on economic development and energy utilization. It is estimated that CO<sub>2</sub> sequestration in U.S. will cost over \$1 trillion annually for CO<sub>2</sub> geological sequestration by complying with the Kyoto Protocol. Even if the global temperature increase of 0.7 degrees Celsius over the past 100 years is solely caused by anthropogenic CO<sub>2</sub> emission, the change on the global temperature by sequestering all the CO<sub>2</sub> emitted exceeding the 95% of 1990 level will be negligible. The dynamic climate and weather patterns on Earth will make it impossible to be verified.

This work gives a realistic situation on the potential impacts of commercial scale CO<sub>2</sub> sequestration projects on economics, environment, and the global climate change. The findings of this study can be used to evaluate the risks of the CO<sub>2</sub> geological sequestration projects.

### **Introduction**

Because of the increasing world energy demand, carbon producing fossil fuels will continue to be the dominant energy component for decades to come no matter how well “zero emission” renewable energy is developed. Geological sequestration is often the first choice for carbon storage due to the massive underground capacity and relatively mature injection technology. Coal fired power plants which contribute about 40% of emissions are the most likely source to provide CO<sub>2</sub> for sequestration. However, the scale of CO<sub>2</sub> injection into geological formations worldwide will depend on the emission cap, climate change policies and affordability of each individual country.

Fig. 1 shows the measured and projected CO<sub>2</sub> emissions from U.S. and worldwide due to fossil energy consumption from 1990 to 2030. The Kyoto Protocol requires developed countries to reduce CO<sub>2</sub> by 5% of the 1990 level beginning in 2008. In order to comply with the Kyoto Protocol, enormous amount of CO<sub>2</sub> has to be sequestered, as shown in Fig. 1 and Table 1.

Depleted oil and gas reservoirs, deep saline formations, and unmineable coalbeds are usually considered as the most applicable CO<sub>2</sub> sequestration formations. The criteria for a candidate formation include injectivity, storage capacity, and containment. A minimum depth of 800 m is recommended to ensure the safety of potable water aquifers. At this depth CO<sub>2</sub> will reach supercritical state (CO<sub>2</sub> critical point is at 1071 psi and 87.9°F), wherein the density of CO<sub>2</sub> is 600 to 800 kg/m<sup>3</sup> and is optimal for storage (van der Meer, 1993). A maximum cutoff depth of 3300 m is also suggested to keep the compression costs reasonable (Winter and Bergman, 1993).

The petroleum industry has been injecting CO<sub>2</sub> for enhanced oil recovery (EOR) for over 30 years. Thus, the injection rates for EOR may provide the approximate ranges for sequestration but this should be considered as the best case scenario and the starting point of discussion. While EOR injection is done under steady-state conditions, sequestration implies

permanent storage, i.e., injection into a reservoir enclosed within no-flow boundaries. Such injection is the reverse of pseudosteady-state production and for typical reservoir pressure differences of e.g. 3000 psi, total produced or injected volume of liquid CO<sub>2</sub> could not exceed 3 to 5% of pore volume with injectivity reduced as reservoir pressure increases.

Table 2 shows the CO<sub>2</sub> injection rates for two CO<sub>2</sub>-EOR units, SACROC Unit and Wasson Denver Unit in the Permian Basin (Stevens et al., 2000), and a case study for potential CO<sub>2</sub>-EOR and sequestration for the Grieve field in Wyoming (Wo et al., 2008). Permeability of 10 md is recommended as a cutoff for selection of suitable sequestration sites. The average injection rates at the Wasson Denver Unit can be used as the lower limit for evaluation. The Grieve field has exceptionally high permeability and low initial reservoir pressure, and the average reservoir thickness is about 45 ft, providing an optimistic example of the upper limit for CO<sub>2</sub> injection rates.

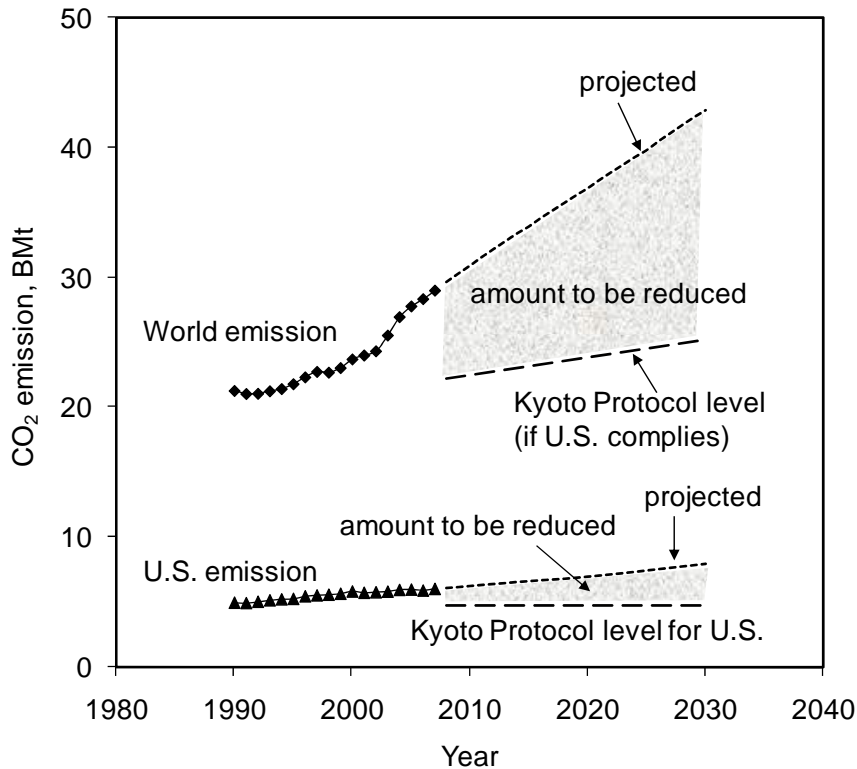


Fig. 1 CO<sub>2</sub> emission in U.S. and worldwide (from [www.eia.doe.gov](http://www.eia.doe.gov)).

Table 1 Amount of CO<sub>2</sub> exceeding Kyoto Protocol level

Year	in U.S., BMT*	worldwide, BMT
2008	1.32	7.35
2010	1.48	8.33
2015	1.85	10.69
2020	2.21	13.00
2025	2.69	15.29
2030	3.21	17.70

\* billion metric tonne

Table 2 Examples of CO<sub>2</sub> injection rates for EOR at various levels of permeability

Field	Rock type	Permeability, md	Depth, ft	Reservoir pressure, psi	Average CO <sub>2</sub> injection rate, tonnes per year/per well
SACROC Unit	carbonate	33	6,700	3,122	60,635-20,211 (from 1972-1996)
Wasson Denver Unit	carbonate	5 ~ 8	5,200	1,805	22,410-17,360
Grieve field	sandstone	220	6,900	< 1,000	~ 192,000 (simulation projection)

If the extra CO<sub>2</sub> from Table 1 is to be injected according to the average rates in Table 2, the U.S. will need 66,382 wells in 2008 to dispose of the additional CO<sub>2</sub>. The number of wells will have to increase to more than 160,000 by 2030,

assuming that the permeabilities and reservoir pressures are similar to that of the Wason Denver Unit, and fluids are produced during injection (Table 3). For comparison, about 40,000 oil and gas wells are drilled annually in the United States.

The injection rate of Class I wells for disposal of fluid wastes can also be used as an analog for CO<sub>2</sub> injection rate. Under the Underground Injection Control (UIC) program, fluid wastes have been injected into the saline aquifers below the underground sources of drinking water through Class I injection wells ([www.epa.gov](http://www.epa.gov)). There were 484 Class I wells nationwide as of June 2005 (504 wells as of September 2007). The average injection rate for the active wells was about 117,072 tonnes per year/per well (GWPC, 2005), which is within the range of the estimated in Table 2. However, the leakage of some of those Class I wells has brought legal and regulatory problems (Keith et al, 2005). It is easy to imagine the similar problems several orders more severe if vast amount of CO<sub>2</sub> is injected.

Table 3 Estimated number of wells needed for CO<sub>2</sub> injection

Year	Wells needed in U.S.		Wells needed worldwide	
	Wason Denver Unit avg. rate	Grieve field rate (simulation projection)	Wason Denver Unit avg. rate	Grieve field rate (simulation projection)
2008	66,382	6,875	369,626	38,282
2010	74,428	7,709	418,909	43,386
2015	93,035	9,636	537,592	55,678
2020	111,140	11,511	653,760	67,709
2025	135,278	14,011	768,922	79,636
2030	161,429	16,719	890,119	92,188

The frequently mentioned CO<sub>2</sub> sequestration project, Weyburn Project, has the dual purposes of EOR and carbon sequestration. The project started in 2000. CO<sub>2</sub> from the Great Plains Synfuels plant in Beulah, North Dakota is pumped 200 miles to the Weyburn oil field in southeastern Saskatchewan at a rate of 3000 to 5000 ton/day through pipelines. Over the project's 20 year lifetime, 20 million tonnes of CO<sub>2</sub> is expected to be injected into the field (Orr, 2004; Freund et al., 2005). In 2008 alone 1,320 million tonnes of CO<sub>2</sub> has to be sequestered to meet the Kyoto Protocol standard (Table 1), which means that 1,320 Weyburn projects are needed in U.S if 100% of the injected CO<sub>2</sub> stays buried.

Nevertheless, there are exceptions on the injection rates. The Sleipner West project in North Sea, which was designed for a lifetime of 25 years, is so far the leading CO<sub>2</sub> sequestration project in the world. Since September 1996 CO<sub>2</sub> extracted from an offshore natural gas production field has been injected into an aquifer 1000 m under the seafloor with 1 million tonnes a year injection rate through a single well (Kårstad, 2002). The exceptionally high injection rate is attributed to the vast aquifer size (200 to 250 m in thickness), very high permeability, and poor consolidation of the aquifer sandstones. However, this kind of formations is very young and may lack the cap rock it needs for the CO<sub>2</sub> sequestration purpose. Certainly, a lot fewer wells will be needed if this kind of formations with good seals can be located.

### Uncertainties and Risks of Carbon Geological Sequestration

Under supercritical conditions, CO<sub>2</sub> is less dense than water and tends to migrate to the top of the storage formation due to the buoyancy force. It is inevitable that the highly pressured CO<sub>2</sub> will leak at some extent due to the permeable nature of the porous rocks, causing uncertainties on the storability of the reservoirs. Another serious problem for CO<sub>2</sub> injection is the decrease of injectivity over time, because of the scaling induced by reactions between CO<sub>2</sub> and the formation water and the rock surface, and/or other formation damage factors. The early breakthrough of CO<sub>2</sub> during injection due to the heterogeneity of the formation will affect both injectivity and containment and slow down the sequestration process in oil/gas reservoirs and coalbeds.

In the published literature, the uncertainties and risks of carbon geological sequestration have been analyzed at some extent from surface equipment to underground reservoirs. Stevens et al. (2000) listed the major barriers to the use of depleted oil and gas fields for CO<sub>2</sub> storage, from CO<sub>2</sub> capturing to post injection safety. The study of Damen et al. (2003) emphasized on the health and environment issues. Benson et al. (2003) summarized the lessons learned from all the previous experiences including occupational CO<sub>2</sub> exposures, natural gas transportation and storage, the storage of industrial wastes including nuclear waste disposal in underground reservoirs. Wo et al. (2004) analyzed the risks and uncertainties of unmineable coalbed sequestration and developed a mathematical model for probabilistic risk assessment for carbon sequestration in geologic formations. They used the following inquires to determine a risk factor: the cause of a failure; the likelihood of a failure; the likely amount of CO<sub>2</sub> leaked; the consequences after a failure; and the cost if the failure is remediable.

The critical issues for commercial scale CO<sub>2</sub> sequestration in geologic formations are the uncertainties of the geology, the risks to the environment, and the inevitably immense financial burden. The advantage proclaimed in most of the CO<sub>2</sub> sequestration literature about cost offsetting by CO<sub>2</sub>-EOR in oil reservoir and CO<sub>2</sub>-enhanced coalbed methane recovery (ECBM) in coalbeds is only for relatively small scale CO<sub>2</sub> injection. The benefit becomes negligible when CO<sub>2</sub> is injected at a scale such as the level set by the Kyoto Protocol since the costs of obtaining high purity CO<sub>2</sub> and injection operations will be orders of magnitude higher.

### Oil and gas reservoirs

Due to the availability of the geologic information and the known history of the endurance of the seals and traps, oil and gas reservoirs are considered as the best candidates. The main mechanisms for storing CO<sub>2</sub> in oil and gas reservoirs are structure trapping and solubility trapping. The major criteria for oil and gas reservoirs as CO<sub>2</sub> storage sites are the capacity, injectivity, lithology, and caprock integrity (Taber et al., 1997; Shaw and Bachu, 2002). Assuming the rock is incompressible and oil and gas are produced during CO<sub>2</sub> injection, the specific capacity for oil and gas reservoirs  $C_{o-g}$  can be expressed as (Kovscek, 2002),

$$C_{o-g} = \rho_{CO_2}(1 - s_{ir} - s_{wi})\phi + s_{wi}\phi C_s \quad (1)$$

where  $\rho_{CO_2}$  - CO<sub>2</sub> density as function of pressure and temperature;

$\phi$  - rock porosity;

$s_{ir}$  - residual oil or gas saturation;

$s_{wi}$  - connate water saturation;

$C_s$  - mass of CO<sub>2</sub> dissolved per unit volume of water,

Since it takes hundreds or even tens of thousands of years for CO<sub>2</sub> to dissolve in formation water (Ennis-King and Paterson, 2003),  $C_s$  is very small and may be negligible. The uncertainties and risks can be summarized by the following according to the major criteria.

#### a. Decreased injectivity

As shown in Table 2, the injection rate at the SACROC unit decreased by about two-thirds over a 24-year period. The survey for the 135 reservoirs in Permian Basin CO<sub>2</sub>-EOR projects indicated that the injectivity decreases ranged from 10% to as much as 100%, especially for carbonate reservoirs (Grigg, 2002). Similar situation appeared in laboratory flooding tests which showed large permeability decrease as CO<sub>2</sub> went through the rock (Krumhansl et al., 2002). Formation damage caused by reservoir compaction, precipitation of minerals, oil emulsification and bacteria growth can greatly reduce permeability and therefore injectivity.

Furthermore, about two-thirds of the injected CO<sub>2</sub> returns to the surface along with oil and gas production (approximate steady state). Roughly about three times more wells will be needed to keep the same injection rate under unsteady state conditions.

#### b. Uncontrollable containment

Because of the heterogeneity of the formations and the buoyancy force, the flow path of CO<sub>2</sub> cannot be controlled with certainty. The Permian Basin CO<sub>2</sub> injection projects showed that the injected CO<sub>2</sub> in the reservoir either left the intended area, or leaked into upper or even lower zones (Grigg, 2002). For natural CO<sub>2</sub> gas reservoirs, there is evidence of abundant natural CO<sub>2</sub> leakage to the surface, such as in Utah and Colorado (Baer and Rigby, 1978). The pressure fluctuation and/or over pressure during CO<sub>2</sub> injection can also breach the caprock and cause leakage. For example, soil gas measurements have been taken at the Rangely Weber oil field in northwestern Colorado where CO<sub>2</sub> is injected for EOR. The measurements show annual fluxes of about 3800 tonnes CO<sub>2</sub> originating from deep sources over an area of 78 km<sup>2</sup>, corresponding to approximately 0.01% of the annual CO<sub>2</sub> injection rate (Klusman, 2003). Although the leakage is small, it indicates that even oil and gas reservoir caprock is not leakage free. This gives more uncertainties to deep saline aquifers and unmineable coalbeds without caprock.

#### c. Potential serious environmental consequences

CO<sub>2</sub> leakage to potable water aquifers can contaminate the ground water. Under super critical conditions, CO<sub>2</sub> is a highly effective solvent and capable of extracting contaminants from geologic materials such as polycyclic aromatic hydrocarbons. Those toxic compounds could be mobilized and could compromise water quality in nearby aquifers (Stevens et al., 2000).

#### d. Energy and financial conflicts

The objective of CO<sub>2</sub>-EOR is to use the minimum amount of CO<sub>2</sub> possible to maximize oil production. Because CO<sub>2</sub> purchasing/preparation accounts for about 50% of the capital and operation costs (Stevens et al., 1999) even from the cheapest CO<sub>2</sub> source, co-produced CO<sub>2</sub> is usually separated from the oil and gas and recycled to the maximum economic limit. Leakage from any section is closely monitored to prevent losses. As part of the decommissioning, reservoir pressure is usually blown down to maximize oil recovery and to avoid liability caused by CO<sub>2</sub> leakage at a later time.

On the contrary, permanently storing as much anthropogenic CO<sub>2</sub> as possible in a reservoir is the ultimate goal for carbon sequestration. Permanently sequestering CO<sub>2</sub> in oil and gas reservoirs hampers the development of energy resources. With current production techniques, even depleted oil and gas reservoirs contain a substantial amount of residual oil and gas (5 to 50%). As new and more advanced techniques are developed, the trapped oil and gas may become recoverable. When a reservoir is used as CO<sub>2</sub> storage site, converting it back to production reservoir can obliterate the effort of CO<sub>2</sub> sequestration.

CO<sub>2</sub> stored in gas reservoirs can devalue the residual gas and eliminate the possibility of using those reservoirs as natural gas storage reservoirs for market supply.

### Deep saline formations

CO<sub>2</sub> storage in deep saline aquifers will either induce a pressure increase in the formation by compression of rocks and water in a closed reservoir, or displace formation water into adjacent formations or to the surface from an open reservoir. The recognized mechanisms for storing CO<sub>2</sub> in deep saline formations include structural trapping, hydrodynamic trapping, and mineralization. Unlike oil and gas reservoirs, geologic information related to brine formations is scarce and brine formations have never been tested to hold large amount of highly pressured fluids, thus the uncertainties increase.

Similar to oil and gas reservoirs, if water is produced while CO<sub>2</sub> is pumped in or the aquifer is connected to open sources, the specific capacity of a deep saline formation can be expressed as:

$$C_{saline} = \rho_{CO_2}(1 - s_{wi})\phi + s_{wi}\phi C_s \quad (2)$$

For the same reason mentioned above,  $C_s$  may be negligible. For a closed saline reservoir, the injectivity of CO<sub>2</sub> solely relies on the compressibility of the rock and water, which is about  $6 \times 10^{-6}$  psi<sup>-1</sup>. The injection rate decreases as more CO<sub>2</sub> is injected due to the limited system compressibility. According to Darcy's equation, the injectivity index of liquid for an undamaged well under unsteady state, is the well known:

$$J = \frac{q}{\Delta p} = \frac{2\pi kh}{\mu \ln(0.472r_e / r_w)} \quad (3)$$

where  $q$  - volumetric flow rate at the bottom of the injection well;  
 $h$  - formation thickness;  
 $\Delta p$  - difference between the injection and formation pressures;  
 $k$  - formation permeability;  
 $\mu$  - injected phase viscosity;  
 $r_e$  - equivalent closed formation radius;  
 $r_w$  - wellbore radius.

While the injectivity index will remain constant if the near well zone is not damaged, the injection rate will decline just by virtue of the unsteady state injecting into a closed system. As shown in Fig. 2, reservoir pressure increases as more CO<sub>2</sub> is injected. Usually the injection pressure is not permitted to exceed the reservoir fracture pressure in order to prevent leakage. Assuming  $p_{fm}$  is the formation fracture pressure, the maximum available reservoir volume for CO<sub>2</sub> is  $V_{max}$ , we have

$$V_{max} = c_t \pi (r_e^2 - r_w^2) h \phi (p_{fm} - p_i) \quad (4)$$

Where  $c_t$  is the reservoir total compressibility,  $\phi$  is the rock porosity. If the injection rate is denoted as  $q_{0.5V_{max}}$  when the injected volume is half of the available maximum volume, i.e.  $0.5V_{max}$ , the dimensionless injection rates and injected volumes can be calculated as:

a) Before flow reaches the reservoir boundary:  $r \in [r_w, r_e]$

$$q / q_{0.5V_{max}} = \frac{2r_e^2 \ln(r_e / r_w) - (r_e^2 - r_w^2)}{\ln(r / r_w)(r_e^2 - r_w^2)} \quad (5)$$

$$V / V_{max} = \frac{(r^2 - r_w^2) / [2 \ln(r / r_w)] - r_w^2}{r_e^2 - r_w^2} \quad (6)$$

b) After flow reaches the reservoir boundary:  $p_e \in [p_i, p_{wf}]$

$$q / q_{0.5V_{max}} = \frac{(p_{wf} - p_e)[2r_e^2 \ln(r_e / r_w) - (r_e^2 - r_w^2)]}{\ln(r_e / r_w)(r_e^2 - r_w^2)(p_{wf} - p_i)} \quad (7)$$

$$V / V_{max} = 1 - \frac{(p_{wf} - p_e)[r_e^2 - (r_e^2 - r_w^2) / (2 \ln(r_e / r_w))]}{(p_{wf} - p_i)(r_e^2 - r_w^2)} \quad (8)$$

Where  $p_{wf} = p_{fm}$  is the injection pressure,  $p_e$  is the boundary pressure.

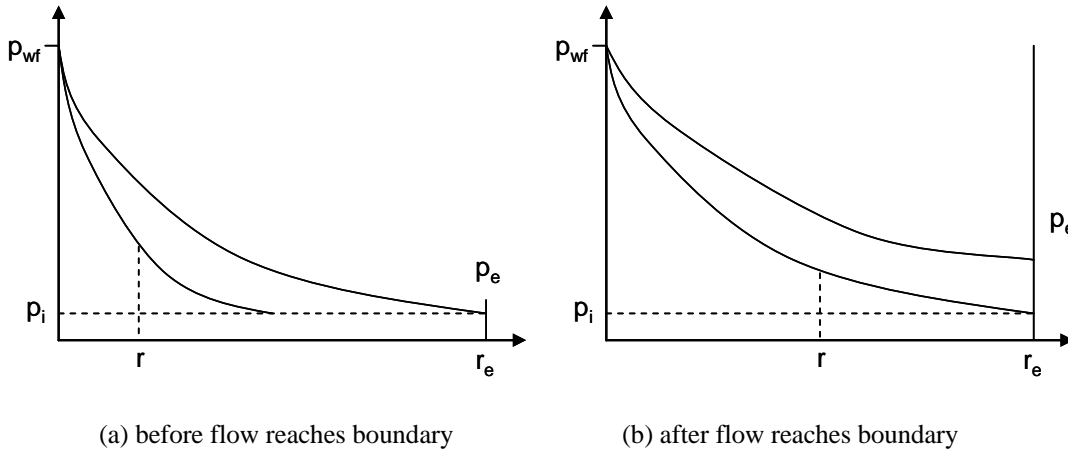


Fig. 2 Injection at constant pressure for a finite reservoir.

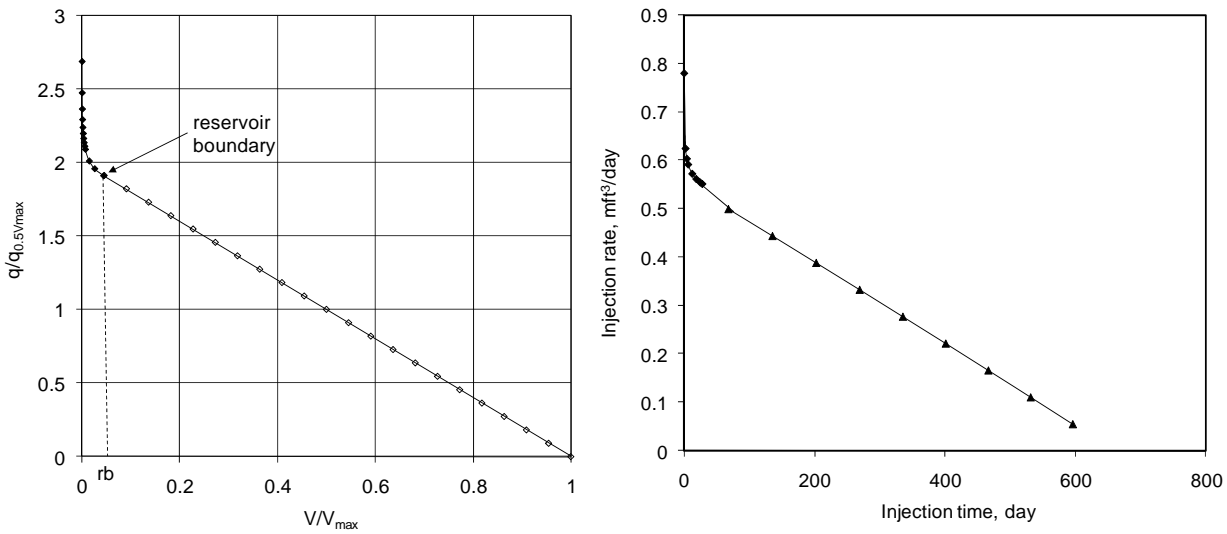
If a formation is 10 miles in diameter and 3000 ft in depth, the formation temperature is about 110°F, the parameters are assumed to be

$$r_e = 5 \text{ miles} = 26,400 \text{ ft}, r_w = 0.328 \text{ ft}, h = 100 \text{ ft}, p_{wf} = p_{fm} = 2,400 \text{ psi}, p_i = 1,350 \text{ psi}, \phi = 0.2, c_i = 6 \times 10^{-6} \text{ 1/psi}, k = 100 \text{ md}, \mu_{CO_2} = 0.068 \text{ cP}, \rho_{CO_2} = 48.27 \text{ lbm/ft}^3.$$

The dimensionless injection decline curve  $q/q_{0.5V_{max}}$  versus  $V/V_{max}$  can be plotted as Fig. 3a. It indicates that as more CO<sub>2</sub> is injected into the reservoir, the injection rate declines rapidly if the injection pressure is constant.

The maximum injection volume can be calculated with Eq.4:

$$V_{max} \approx 275.75 \text{ million ft}^3 \approx 6.04 \text{ million tonnes (mt)} \tag{9}$$



(a) Dimensionless injection rate and injected volume

(b) Injection rate vs. time

Fig. 3 Relationship between CO<sub>2</sub> injection rate, injected volume and time for a closed deep saline formation.

From Fig.3a, when the flow reaches the reservoir boundary as illustrated in Fig.2a, the volume injected is:

$$V_{rb} = V/V_{max} |_{rb} \times V_{max} = 0.044264 \times 275.75 = 12.206 \text{ million ft}^3 \text{ (mft}^3) \tag{10}$$

According to Economides et al. (2008), the injection rates for this amount of CO<sub>2</sub> can be calculated as:

$$q(t) = \frac{kh(p_{wf} - p_i)}{29\mu_{CO_2}} (\log t + \log \frac{k}{\phi\mu_{CO_2}c_i r_w^2} - 3.23) = \frac{5.325}{\log t + 6.83} \tag{11}$$

where time  $t$  is in hours,  $q(t)$  is in  $\text{mft}^3/\text{day}$ . Combining Eqs.8 and 9 we have

$$V_{rb} = \int_0^{t_{pss}} \frac{5.325}{\log t + 6.83} dt \quad (12)$$

where the time,  $t_{pss}$  at which the flow reaches the boundary is (Economides et al., 2008):

$$t_{pss} = \frac{\phi \mu_{CO_2} c_t A}{0.000264k} t_{DA} = 676.4 \text{ (hrs)} \quad (13)$$

assuming drainage shape factor  $t_{DA} = 0.1$ .

When the injection time  $t > t_{pss}$ , the injection rate can be calculated with the following equation:

$$q = 5.55 \times 10^{-4} (2400 - \bar{p}) \text{ (mft}^3/\text{day)} \quad (14)$$

Where  $\bar{p}$  is the average pressure of the formation. The injection time can then be estimated, as shown in Fig.3b (Economides et al., 2008). With the injection rate decline such as this, a lot more wells are needed for deep saline aquifer  $\text{CO}_2$  injection than for that of oil and gas reservoir.

#### a. Injectivity loss

Similar to oil and gas reservoirs, decreased injectivity is expected depending on the rock and water composition, especially for carbonate reservoirs. Formation damage caused by reservoir compaction, precipitation of minerals, and bacteria growth can reduce near-well permeability and therefore injectivity. The injection pressure buildup will affect the injection rate depending on the size of the aquifer and the formation permeability.

#### b. Uncontrollable containment

The free  $\text{CO}_2$  due to its density will migrate to the highest point in the reservoir. Lateral spreading of  $\text{CO}_2$  is also uncontrollable if there is no structural seal. Thus, the structural geometry will have a strong influence on the migration direction. Injection of  $\text{CO}_2$  into an aquifer will result in an increase in pore pressure, which, in turn will alter the effective stress leading to permeability and porosity variations. A sufficiently large change in the stress field can cause failure by allowing  $\text{CO}_2$  to leak through fractured rock and may give rise to seismicity (Rutqvist and Tsang, 2002). Using the Sleipner West project as an example, the injected  $\text{CO}_2$  has vertically leaked through a 5 meter mud rock seal within the aquifer (Torp and Gale, 2003). As more  $\text{CO}_2$  is injected, the vertical leakage pathway effective permeability of  $\text{CO}_2$  will increase due to the saturation increase. More leakage may be expected.

#### c. Capacity loss

It was stated earlier that only 3 to 5% of pore volume is available if the saline aquifer has no flow boundaries. For non-closed saline formation,  $\text{CO}_2$  injection is a process of  $\text{CO}_2$  displacing saline water. The heterogeneity of the saline formations controls the mobility ratio and the displacement efficiency. The reservoir capacity decreases if displacement efficiency of in-situ fluid is low (Jessen et al., 2001). Scaling and mineralization also reduce the reservoir capacity.

#### d. Financial burden

Geologic information is scarce for saline formations. To acquire detailed geological information before  $\text{CO}_2$  injection is necessary but costly. Torp and Gale (2003) estimated that it could increase the cost of coal- or gas-fired power stations by 50 - 80% if operations similar to the Sleipner West project are performed.

### **Unmineable coalbeds**

Adsorption of  $\text{CO}_2$  molecules on coal particles at high pressure is the most likely mechanism for  $\text{CO}_2$  storage in the coalbeds. The capacity mainly depends on the quality of coal which dominates the  $\text{CO}_2$  adsorption quantity and the  $\text{CO}_2$ -coal contact which is affected by coalbed heterogeneity. The hydrodynamic trapping can also take place depending on the displacement efficiency.

#### a. Injectivity problem

One potential problem is the coal swelling because of  $\text{CO}_2$  injection. Coal swells/shrinks from the adsorption/desorption of gases. During methane production, desorption of  $\text{CH}_4$  molecules results in separation of coal cleats because of the pressure drop, permeability of the coal increases enormously, sometimes a few orders of magnitude. When  $\text{CO}_2$  is injected into the coal, the process is reversed, pressure increases and permeability decreases. This phenomenon severely affects the injectivity of the coalbeds, especially at the low pressure range. At higher pressure range the permeability increases, but the cost for  $\text{CO}_2$  injection will also increase.

The Allison unit in San Juan Basin, New Mexico, is the only multi-well, multi-year field test for  $\text{CO}_2$  injection into coalbeds in the world so far. The pilot test included 4 injection wells, 16 CBM production wells and a pressure observation

well (Reeves et al., 2002). The CO<sub>2</sub> being injected at Allison was sourced from McElmo Dome CO<sub>2</sub> field - a natural CO<sub>2</sub> reservoir. A total of 4.7 Bcf of CO<sub>2</sub> (about 0.25 million tonnes) was injected into the Allison unit intermittently during the lifetime of the operation from 1995 to 2000 (Reeves et al., 2003; Kuuskraa, 2003). CO<sub>2</sub> initial injection rate was about 5 MMcf/d in 1995, the injection rate decreased to about 3 MMcf/d in a few months (Reeves, 2001).

#### b. Uncontrollable containment

CO<sub>2</sub> and CH<sub>4</sub> leakage can occur through pre-existing faults and discontinuities and through outcrops. Historically, methane seepage has been observed from various locations and evidence of methane contamination in groundwater has been documented (Wo et al., 2004). Methane seepage has been observed from the Pine River (Oldaker, 1999), South Texas Creek, Valencia Canyon, Soda Springs, and other areas along the north and west Fruitland outcrops (BLM, 1999; Wray, 2000). These observations indicate the possibility of injected CO<sub>2</sub> likely following the methane leakage pathways to leak toward outcrops or the surface. The swelling of coal can induce additional faulting to promote the leakage of CO<sub>2</sub> from the coal seams. Most coal seams around the world are faulted and have very thin beds (1 - 5 m) and low permeability (1 to 5 md). All those factors would make the seams less feasible as CO<sub>2</sub> storage reservoirs (Haszeldine, 2004).

#### c. Environmental problem

Water resources may be contaminated due to the leakage of injected CO<sub>2</sub>. The water salinity of a lot of coalbeds such as the Powder River Basin coalbeds is much lower than 10,000 ppm regulated by EPA as the upper limit for potable water. The extract of underground water resource at a later time can reduce the formation pressure and result in desorption of CO<sub>2</sub> from the coal seams and leakage.

Although unmineable coalbed are claimed to be one of the most promising sequestration sites for CO<sub>2</sub>, no data have appeared to support this claim. On the contrary, leakage and swelling seem universal for coalbeds.

For long term carbon geological sequestration, leakage can occur because of various factors including natural disasters. Leakage of high purity CO<sub>2</sub> within the formation and the extraction of toxic chemicals from the formation could cause groundwater contamination. The sudden leakage in large amount could pose danger to human lives and the environment. The enormous cost of the operations and liability due to potential CO<sub>2</sub> leakage result in the controversies in establishing regulation and policy systems.

### **The Policies and Regulation for CO<sub>2</sub> Sequestration**

The regulatory issue for CO<sub>2</sub> sequestration has been an active topic and extensively researched. Regulations for surface engineering systems for CO<sub>2</sub> sequestration, such as the occupational exposure limit, transportation, pipeline regulations etc., have been suggested to be established with the existing regulations and the experiences from the industry (BLM, 1999; Benson et al., 2003; Solsbery et al, 2003). Small scale experimental projects for CO<sub>2</sub> injection for storage have been regulated in U.S. by the federal Environmental Protection Agency under the UIC program (Dougherty and McLean, 2007). Injection of CO<sub>2</sub> for EOR and ECBM has been regulated under the same program but a less restrictive classification since the 1970s.

However, due to the uncertainties and risks for commercial scale long term CO<sub>2</sub> storage, there are no regulations and policies related to injection well classifications, monitoring and verification of the injected CO<sub>2</sub>, and accepted leakage rate which are tied to legal liability and financial responsibilities. The classification of CO<sub>2</sub> has caused contradictions. No country or state in the world has made firm policies over issues such as the ownership of the injected CO<sub>2</sub>, the long term liability and responsibility (CSLF, 2004).

#### *The classification of CO<sub>2</sub>*

The classification of CO<sub>2</sub> as either a waste or a commodity has been continuously debated (CSLF, 2004; IOGCC, 2005). Although CO<sub>2</sub> has been ruled as a pollutant by the U.S. Supreme Court in 2007, in current situation, no matter how CO<sub>2</sub> is defined, high concentration CO<sub>2</sub> has always been an expensive commodity used in modern industry, especially in food processing and CO<sub>2</sub>-EOR operations. Insufficient supply of CO<sub>2</sub> has been an ongoing problem for CO<sub>2</sub>-EOR projects, and large amount of high purity CO<sub>2</sub> is being produced as a commodity from natural CO<sub>2</sub> reservoirs to meet the growing industrial needs. The commodity nature has not been changed by the Supreme Court ruling.

It is generally required that the sequestered CO<sub>2</sub> be purified to at least 95% to prevent pipeline from corrosion and underground water from contamination by toxic elements (Bliss, 2005). If the amount of high concentration CO<sub>2</sub> listed in Table 1 is available for permanent storage, the definition of CO<sub>2</sub> as a commodity becomes invalid. The small portion used by the industry becomes negligible. The sequestered CO<sub>2</sub> is solely waste even without classification. Nevertheless, the category of CO<sub>2</sub> in the waste series will affect the environmental regulations and legal issues over the CO<sub>2</sub> sequestration.

#### *The ownership of injected CO<sub>2</sub>*

In the current situation, CO<sub>2</sub> is still extracted from natural reservoirs to meet the increasing demand for industry use. The ownership of high concentration CO<sub>2</sub> is linked to profit since CO<sub>2</sub> is a commodity. There is no need to discuss about the ownership issue for the stored CO<sub>2</sub>. The reservoir will be closely monitored and leakage remediated. If CO<sub>2</sub> is abundant enough for commercial scale sequestration, the ownership will only stand for long term financial liability, including responsibility for the CO<sub>2</sub> separation, transportation, storage site selection, pore space leasing, CO<sub>2</sub> injection, post-storage long



term management, remediation if a leakage occurs. The limited life span of coal-fired power plants (average 40 years in U.S.) and business entities makes the ownership more complicated. However the ownership is assigned or carbon tax imposed, all the cost will eventually pass on to the individual energy users, which will result in more energy utilization, slower economic development, and higher energy price.

### **Perspective**

Policies and regulations about carbon management are universal issues. A global agreement will be needed for the decrease of any significant carbon emission. It is not likely to happen soon enough due to the substantial differences from one part of the world to another, such as industrial development, financial situation, and population distribution. Actually even a global agreement is not enough. Taking Kyoto Protocol as an example, within the 36 developed countries required to reduce CO<sub>2</sub> emission as of November 2007, almost all increased CO<sub>2</sub> emission after they ratified the Protocol.

## **Potential Effect on Economy, Environment and Climate**

### **Cost analysis**

#### a. Cost for capturing, compression, and transportation

CO<sub>2</sub> concentration in flue gas is only about 8 to 13% by volume. Flue gas also contains N<sub>2</sub>, O<sub>2</sub>, H<sub>2</sub>O, NO<sub>x</sub>, SO<sub>x</sub>, and other toxic elements. CO<sub>2</sub> must be separated from those gases before transportation and injection. According to the Department of Energy 2006 estimation, CO<sub>2</sub> capture from flue gas alone costs about \$150/ton of carbon with the current available technology. Capturing 90% of CO<sub>2</sub> from Integrated Gasification Combined Cycle (IGCC) power plants takes 20-25% of the plant's energy. It would increase the capital costs by 47% and the total cost of electricity by 38% (EPA, 2006). Koopman (2007) estimated that the compression cost to liquefy CO<sub>2</sub> is about \$17/tonne of CO<sub>2</sub>. The costs of capture and compression for U.S. CO<sub>2</sub> program are listed in Table 4 if Kyoto Protocol is complied.

Table 4 Carbon capturing and compression costs in U.S.

Year	Amount of CO <sub>2</sub> exceeding Kyoto Protocol in U.S., BMt	Capturing cost, billion dollars	Compression cost, billion dollars
2008	1.32	59.52	22.44
2010	1.48	66.74	25.16
2015	1.85	83.42	31.45
2020	2.21	99.66	37.57
2025	2.69	121.30	45.73
2030	3.21	144.75	54.57

The transportation cost varies depending on the distance between the source point to the injection site. The cheapest way to transport CO<sub>2</sub> is by pipeline. Pipeline construction costs about \$2 million/mile, and the subsidiary power transmission line is about \$0.9 to \$1.7 million/mile (Virden, 2007). Besides the capital cost for pipelines, transmission lines and compressor stations, the operational costs including power, maintenance and labor will be added as soon as the operation starts.

#### b. Well drilling and related costs

The CO<sub>2</sub> injection well for the Sleipner West project cost \$15 million in 1996. An observation well was not drilled because of the high cost - the estimated cost was about 45 million Euros then (Torp and Gale, 2003). It is reasonable to assume an average of \$10 million to drill and complete a CO<sub>2</sub> injection well, along with the ancillary piping, storage, valves, and other equipment in U.S. Table 5 lists the estimated cost for well drilling and related equipment for Kyoto Protocol scale CO<sub>2</sub> sequestration operations in U.S. Since injectivity of wells and capacity of reservoirs are not considered for the number of wells listed, more wells including observation wells will be needed to ensure all of the CO<sub>2</sub> sequestered.

#### c. Post injection management cost

Post injection management includes monitoring and verification, remediation if leakage occurs, and litigation issues. Actual cost can vary substantially depending on the regulations and policies.

#### d. The cost to the economic development

Complying with the Kyoto Protocol emission standard, the U.S. economic development will be greatly hampered due to the higher cost of energy and over use of energy by CO<sub>2</sub> separation and sequestration operations. Over \$1 trillion annually may be needed for the operation if all the cost is considered. Nevertheless, the effort may be worthy if the climate change can be controlled or the global warming can be stopped. The following analysis indicates otherwise.

Table 5 Estimated cost for well drilling and accessories in U.S.

Year	Wasson Denver Unit avg. injection rate		Simulated Grieve field injection rate	
	No. of U.S. wells	cost, trillion dollars	No. of U.S. wells	cost, billion dollars
2008	66,382	0.66	6,875	68.75
2010	74,428	0.74	7,709	77.09
2015	93,035	0.93	9,636	96.36
2020	111,140	1.11	11,511	115.11
2025	135,278	1.35	14,011	140.11
2030	161,429	1.61	16,719	167.19

### *CO<sub>2</sub> sequestration and the effect on global temperature change*

The most important point, but mentioned the least, is that how much effect the CO<sub>2</sub> reduction programs eventually have on the global temperature change, which is supposed to be the ultimate goal of the whole operation. Over the last 100 years from 1906 to 2005, the average global temperature increased 0.74°C, as shown in Fig. 4 (NASA, 2008; IPCC, 2007). IPCC observed that the average global temperature increased 0.13°C per decade from 1956 to 2005 and 0.2°C per decade from 1990 to 2005 (IPCC, 2007). The total world anthropogenic CO<sub>2</sub> emission was about 370.4 BMT during 1990 to 2005 period (Figure 1). IPCC also projected that the average global temperature would increase 0.2°C per decade for the next two decades if the CO<sub>2</sub> emission was within the projected range shown in Fig. 1 (IPCC, 2007). Therefore, global temperature would increase about 0.44°C from 2008 to 2030 without CO<sub>2</sub> emission deduction.

For the worst case scenario, assuming that the global temperature will increase 0.44°C from 2008 to 2030 and is solely caused by the anthropogenic CO<sub>2</sub> emission, if all the Kyoto Protocol countries and the U.S. comply with the Protocol (assuming 78% of the world emission as of December 2007 which is going to decrease due to the increased emission from the developing countries), the amount of CO<sub>2</sub> that needs to be reduced will be 288.93 BMT. The worldwide total emission during this period is 834.7 BMT. The temperature increase will be

$$\Delta T |_{2008-2030} = 0.44(1 - 288.93/834.7) = 0.29^\circ\text{C} \quad (15)$$

assuming that the IPCC projection is accurate and all the CO<sub>2</sub> is reduced or sequestered.

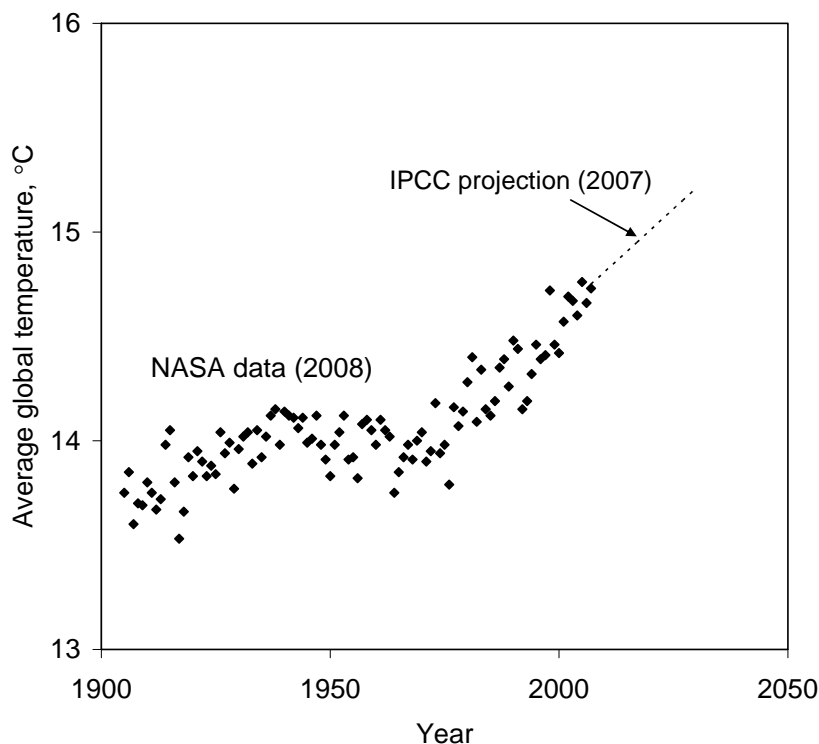


Fig. 4 History and projection of the average global temperature.

IPCC also pointed out that even if CO<sub>2</sub> and other greenhouse gases are kept at constant at year 2000 level, a temperature increase of 0.1°C per decade would be expected for the next century due to the inertia in the climate and the thermal expansion (IPCC, 2007), translating to a 0.22°C increase during 2008 to 2030 even all human activity is stopped. Thus, the Kyoto Protocol effort will only reduce the global temperature by 0.07°C over 22 years. Hansen et al. (2007) indicated that there is about 0.1°C global temperature variations of amplitude associated with a 10-11 year solar cycle. Therefore, any likely small effect on global temperature by Kyoto Protocol scale CO<sub>2</sub> deduction may not be reasonably detectable.

Furthermore, detecting and verifying any small change on global temperature over a long period can be rather difficult considering the dynamic climate and weather patterns which are affected by many factors including fluctuations from the sun, the universe, and the earth itself. The 0.7°C global temperature decrease between January 2007 and January 2008 measured by NASA and other institutions (Chapman, 2008) certainly revealed the versatility and complexity of global temperature change if the global warming trend has not been affected by this sudden thermometer drop.

In the long run, IPCC (2007) stated that the global temperature takes a few centuries or less to reach an equilibrium value of about 5°C above the pre-industry era (or about 4°C above current temperature) due to the thermal expansion alone if CO<sub>2</sub> emission in 2050 is 90 to 140% more than the 2000 level. If the statement is valid, the Kyoto Protocol scale CO<sub>2</sub> reduction effort may never be able to be verified by any temperature measurements, but its detrimental effect on the global economy will immediately be felt by every one.

Finally, if the effect of thermal expansion can last a few centuries, the climate history since the past several centuries may have to be counted, at least partially, for the observed current global temperature increase and forthcoming global temperature measurements, which further complicates the evaluation of the impact of Kyoto Protocol scale CO<sub>2</sub> reduction operations.

## Summary

1. The technology for CO<sub>2</sub> injection to geological formations is readily available. The financial burden is tremendous.
2. There are too many uncertainties and risks for long term CO<sub>2</sub> sequestration. The contradiction between the regulatory framework for CO<sub>2</sub> sequestration and social and economic development is hard to be disentangled.
3. A Kyoto Protocol scale carbon sequestration program will not have detectable effect on global temperature. On the contrary, it may cause serious immediate environmental problems.
4. The Kyoto Protocol will not be able to prevent the global from warming even the temperature is solely caused by anthropogenic carbon emission. Instead, it will cause enormous social hardships and greatly hamper the economic development and energy efficiency of all the countries that abide by it.
5. The most important issues that are largely ignored now are the scale of the carbon sequestration task and the actual risks on the economy and the environment of nations, and actual effect on climate change.

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